Alaska Gasline PORT AUTHORITY

411 4th Avenue
Fairbanks, AK 99701
Phone: (907) 474-2011
Fax: (907) 474-2001

www.allalaskagasline.com

Application

(including requested clarifying information)

Application Check List
Appendix A-1
Certification

Binder 11

AGIA License Application

The Alaska Gasline Port Authority

Submitted Pursuant to the Alaska Gasline Inducement Act (12 43.90)

Executive Summary

The Port Authority was formed in 1999 by the municipalities of the North Slope Borough, Fairbanks North Star Borough and the City of Valdez to develop, build or cause to be built, finance, and operate or cause to be operated a project to monetize Alaska's North Slope natural gas, which would include a trans-Alaska gas pipeline, liquefaction and gas processing facilities and related infrastructure for the transportation of North Slope natural gas to Alaskans and the market ("**Project**" or the "**All-Alaska Gasline**").

1. Objectives of the Alaska Gasline Port Authority

Guided by the mandates of the Statehood Compact, the Alaska State Constitution, and Alaska Statutes, the Port Authority has developed the All-Alaska Gasline Project not only to fulfill the goals and requirements of AGIA, but to provide maximum benefits to Alaska.

Perhaps the most important characteristic of the Project's structure is that, as a public entity, the Port Authority is not driven by the need to maximize its profits, but to provide "maximum benefit" to the people of the State of Alaska. In contrast to entities with natural gas development projects elsewhere in the world that compete internally for corporate investment funds, the Port Authority was formed to advance a single project that is completely within Alaska.

Since its inception, the Port Authority has worked to apply the unique structure of a public/private participation to a natural gas pipeline project with the aim of significantly improving the economic viability and, thus, the likelihood of success of bringing ANS natural gas to Alaskan consumers and the market. This structure enables the Port Authority to have a singular focus on its mission to:

- enable the development of ANS gas to the maximum benefit of all Alaskans, including the distribution of net project revenues;
- promote Alaska hire throughout construction and operation;
- provide access to gas for existing and additional in state petrochemical industries;
- provide for maximum distribution of Alaska's natural gas throughout the State;
- bring ANS natural gas to markets at long-term competitive prices; and
- bring the benefits of a tax-exempt structure to an ANS gas pipeline project.

Throughout the development of the Project, the Port Authority has enlisted the participation of world leaders in the development of large-scale oil and gas projects for expert advice in the areas of: engineering and design, cost estimation, economic modeling, LNG shipping, and LNG and NGL marketing.

2. Over Thirty Years of Public Support for the All-Alaska Gasline Project

The All-Alaska Gasline has consistently been the preferred project of Alaskans statewide. The overwhelmingly supportive votes that created the Port Authority in 1999 and the Alaska Natural Gas Development Authority (ANGDA) in 2002 (ballot language specifically referring to a gas pipeline from the North Slope to Valdez) are only two examples of Alaskans' strong preference for the All-Alaska Gasline.

Dating back as far as the mid 1970's, Alaskans have made it clear that they prefer an All-Alaska Gasline route over a trans-Canadian route:

> <u>Questionnaire Result:</u>
>
> "Dear Fellow Alaskans:
>
> I want to thank all of you who responded to the questionnaire which appeared in the December, 1975, issue of the newsletter.
>
> I received approximately 45,000 responses as of the first of February. The following are the results which are tabulated from the responses received.
>
> Do you support a trans-Alaska gas pipeline as opposed to a trans-Canadian line?
>
> Yes – 85% / No – 8% / Undecided – 9%"
>
> -Senator Ted Stevens
> Newsletter
> December, 1975

There have been numerous (45) resolutions passed by individual communities and the Alaska Municipal League (**"AML"**) in support of the Port Authority's All Alaska Gasline project.

As recently as November 25, 2007, former Governor Walter Hickel provided an unsolicited endorsement of the All-Alaska Gasline and the Port Authority's Application:

> "I am rooting for the Alaska Gasline Port Authority, a consortium of three communities located along the oil pipeline route. I am not privy to their plans or their proposal, but their leadership is outstanding, and they want to build an All-Alaska LNG system, the concept I believe in."
>
> "I support an all-Alaska gas line from Prudhoe Bay to Valdez for the following reasons: a much sooner start up time, more revenue for the state and municipalities, guaranteed access to the gas by Alaskans, value-added jobs that will last generations and flexible markets for our LNG."
>
> Governor Walter Hickel
> "We Alaskans can build our own gas line"
> Comment, Anchorage Daily News
> November 25, 2007

3. The Project

The Port Authority's Project consists of the components described below.

Pipeline

The Project will include an 806-mile overland natural gas pipeline extending from Prudhoe Bay to tidewater at Valdez ("**Pipeline**"), which will run parallel to the existing Trans-Alaska Pipeline System ("**TAPS**"). This will be a dense-phase pipeline, designed to transport Alaska North Slope ("**ANS**") natural gas, which contains a relatively high amount of natural gas liquids ("**NGLs**"). The proposed initial capacity of the Pipeline is approximately 2.7 billion cubic feet per day ("**bcfd**") of natural gas at the Pipeline inlet in Prudhoe Bay. The Pipeline will be capable of rapid capacity expansion through the addition of compression facilities.

The Pipeline will transport ANS natural gas to (i) Valdez for liquids extraction and liquefaction prior to shipping to export markets and (ii) maximum in-State delivery points for meeting local Alaska consumer and commercial needs. The Port Authority anticipates that a delivery point at Glennallen would provide natural gas for a spur line to Palmer that would tie into the South Central gas grid as proposed by the Alaska Natural Gas Development Authority ("**ANGDA**").

The Pipeline will be designed to allow a future tie-in at Delta Junction (550 miles south of Prudhoe Bay) for a later spur line from Delta Junction to the Alaska/Canadian border, following the Alaska-Canada "(**Alcan**") Highway. Although the Port Authority is not actively pursuing the development of such a project at this time, it is committed to working cooperatively with the sponsor(s) of such a project to maximize the options for monetizing ANS natural gas.

Liquefaction and Liquids Extraction Facilities

The Project will include an integrated liquefaction and fractionation facility in Valdez which will: (a) extract the propane and butane (liquid petroleum gases or "**LPGs**"), from the gas transported through the Pipeline; and (b) produce liquefied natural gas ("**LNG**") using three process trains, each with nominal design capacity of approximately five million metric tons per annum ("**mmta**"), for a total LNG production capacity of 15 mmta. The LNG will be exported to Asian markets in Japan, South Korea and Taiwan or to North America. Also included are storage and vessel loading facilities for LNG and LPGs (together with the liquefaction and fractionation facilities, the "**LNG Facilities**").

4. Target Markets for Alaska's Gas

The principal target markets for the Project LNG and NGL are the Pacific Rim markets, specifically the major LNG consuming countries of Japan, South Korea and Taiwan. It is expected that the Project, as currently envisioned, would provide an attractive economic proposition to ANS gas producers participating in the open season, due to the premium pricing available in these markets.

While East Asian constitutes the principal target gas market at this time, the Port Authority has structured the Project in a manner to facilitate access to U.S. and other North American gas markets in three distinct ways.

1. The Project's increased pipeline diameter from Prudhoe Bay to Delta Junction is sufficient to be considered as the "pre-build" of the first 550 miles of the proposed Alcan Highway project to move gas into Canada to potentially displace Canadian gas into the lower 48 market, once the myriad of issues in Canada are resolve so an Alcan Highway pipeline can move forward .

2. The Port Authority is a participant in the open season being held by Sempra LNG for the expansion of the soon to be completed Energia Costa Azul regasification terminal in Mexico, just south of San Diego, California. This facility is at present the only receiving terminal on the West Coast of North America. The Port Authority has also received a letter of support from the only other fully permitted West Coast LNG receiving terminal, located in Kitimat, British Columbia, which would provide access to gas markets on the West Coast or in the Midwest via existing Canadian pipeline infrastructure.

   Should a prospective shipper of Alaska gas be interested in accessing North American gas markets through either of these West Coast terminals, the Port Authority would work under its Teaming Agreement with BGT and its parent company MOL, to provide a cost-effective marine transportation solution in compliance with the Jones Act. BGT currently controls a fleet of eight U.S.-built LNG tankers that, following reflagging, would be available to serve gas transportation to domestic markets.

3. LNG from Alaska to the Pacific Rim market will displace other LNG previously bound for the Pacific rim market but closer to the U.S. market. thereby making it available for U.S. East Coast markets, much like the proposed gasline into Canada may displace Canadian gas into the Midwest.

5. Significant Advantages of the All-Alaska Gasline Project

Superior Economics

5.1 Premium LNG Markets

The Project will allow the value of ANS natural gas to be maximized by providing access to global LNG markets.

Historically, Asian markets have received their natural gas supplies in the form of LNG, under long term supply contracts with LNG prices tied to the price of oil. Many of those contracts are approaching the end of their initial terms and must be renewed. Current market developments have put an upward pressure on the prices for LNG supplied to the East Asian markets. Recently negotiated LNG supply contracts have included revised oil price indexation provisions, resulting in LNG prices close to thermal parity with oil prices.

It is expected that future LNG supply contracts to the Asian markets will retain these pricing features, resulting in prices significantly higher than forecast North American gas prices. According to the Institute of Energy Economics, Japan ("**IEEJ**"), Asian LNG prices are expected to be in the range of 80 to 90 percent of the price of crude oil, which would result in an average premium of approximately \$3.00 per million British thermal units ("**mmBtu**") over projected Henry Hub gas prices.

5.2 Higher Netback Value for Alaska and ANS Producers

Premium prices of LNG, coupled with competitive cost of transportation to the target markets, result in projected superior netback values in comparison with alternative ANS gas transportation proposals, such as a pipeline to Canada. The Project, therefore, would achieve higher returns for the ANS producers of natural gas and higher revenue for Alaska from royalties and production tax on gas.

With the All-Alaska Gasline Project, higher netback values are achieved even with smaller gas volumes than those proposed for other ANS gas transportation projects. The total reserve requirements for the Project are within the existing discovered resource base, resulting in a high degree of confidence that sufficient gas supply commitments would be obtained under the initial open season for the Project.

Table 1 Projected 20-year Average Netback Prices for the All-Alaska Gasline and Alcan Highway Projects

	LNG Base Case (2.7 bcfd)	Alcan 3.0 bcfd	Alcan 4.5 bcfd
Average Netback Price at Point of Produciton (\$ / mmBtu)	**5.43**	**3.42**	**4.33**
30-Year Reserve Requirements (Tcf)	**30**	**34**	**51**

The All-Alaska Gasline Project enjoys a netback pricing advantage ranging from \$1.10 to \$2.00 per \$mmBtu, depending on the gas volume assumptions, resulting in a significant competitive advantage over the proposed Alcan Highway line. Higher netback prices are achieved on the basis of smaller volume and, therefore, smaller reserve requirements to support the Project.

5.3 Market Optionality

Although at the present time it is assumed that LNG volumes will be marketed in East Asia, the Project would allow Alaska and its gas producers to access gas markets worldwide, including gas markets in the Lower 48 United States, and capture the highest possible sales value for gas, including premiums associated with seasonal and other natural gas market variations. Such alternative gas markets can be reached (a) directly through the supply of the Project's own LNG, or (b) through swap or similar arrangements, which are becoming increasingly common in the global LNG industry. The All-Alaska Gasline provides the only way for Alaska to participate in the global gas commodity market of the future.

5.4 Maximum In State Distribution of Gas

The Pipeline will deliver ANS natural gas to Valdez for liquefaction and liquids extraction at the LNG Facilities. The Pipeline will also deliver ANS gas to delivery points along its route to serve in-State demand for natural gas. While AGIA required a commitment of a minimum of 5 offtake points for gas, the Port Authority has identified 18 potential offtake locations.

6. Importance of Gas Supply to South Central Alaska

Gas production in the Cook Inlet is forecasted to fall sharply over the next few years. In June of 2004, a U.S. Department of Energy ("**DOE**") study projected a 75% drop in production from over 200 bcf per year in 2005 to less than 50 bcf per year by 2014.[1] The Alaska Department of Natural Resources ("**DNR**") most recent annual report was slightly more optimistic, estimating Cook Inlet gas production to reach 52.7 bcf per year in 2017.[2]

The impact of this reduction will be dramatic. As supply constricts, medium-term South Central Alaska gas prices will rise significantly, meaning Alaskan consumers can expect increased gas and power utility rates. Reductions in base supply have already begun to directly affect industrial users.

Agrium, which consumes natural gas for the production of urea, was the first industry to suffer from such reductions. Agrium shut down its Nikiski plant in the winter of 2006-2007 so gas could be made available for higher priority home heating. In September of this year, Agrium closed its Kenai fertilizer facility, laying off more than 100 employees.

The Tesoro petroleum refinery at Nikiski which began operations in 1969, processes oil produced from Cook Inlet. It normally uses natural gas as fuel and feedstock for its hydrocracker unit. In late 2006, due to a gas shortage estimated at 42% below the plant's required volumes, it was forced to use its own high-value products, such as butane, propane and ultra-low-sulfur diesel, to fuel the refinery.

It is expected that the Marathon/ConocoPhillips liquefaction facilities in Nikiski, which have been shipping LNG to Japan since 1969, will also cease operation in the next few years.

DOE predicts that around 2011, not only will there not be enough gas for heavy industrial use, but Cook Inlet gas production will no longer be able to supply electric power generation demand.[3] Beyond 2015, consumer gas utility demand is expected to outstrip local supply.[4]

The consequences of not securing the supply of ANS natural gas to the South Central region by 2015 could be severe. The curtailment of industrial consumption of natural gas in Nikiski for the production of urea, refining, and LNG export would result in significant

---

[1] Presentation of Tony Izzo, President/CEO of ENSTAR Natural Gas Company, Energy Supply in South Central Alaska (2006).

[2] State of Alaska Department of Natural Resources, 2007 Annual Report, p. 3-25 (July 2007).

[3] Id. at 11.

[4] Id.

job losses in the Kenai area. Further, power generation along the Railbelt will have to use more expensive fuel substitutes, which could mean not only significant increases in electricity generation costs but could also incur high switchover costs. Alaska, which has the largest undeveloped natural gas reserves in the United States, could become an importer of LNG.

7. Project Labor Agreement

The Port Authority is pleased to commit to a Project Labor Agreement. The Port Authority and appropriate labor representatives have committed, by a signed Letter of Intent, as follows:

- Use of modernized technology with proven results of quality and integrity to increase productivity and efficiency.
- Incorporation of "pre-job" meetings where all aspects of a particular work process are explained and jurisdictional assignments are made; thus lessening the opportunity for workplace disruptions due to mis-assignments.
- Bright lines established for work done under the auspices of the building trades and work under the auspices of the pipeline crafts.
- Use of composite crews where appropriate.
- Development of a formula to assure that wage and benefits and other economic factors are known for the duration of the project.
- Incorporation of methods for complying with Sections 28 & 29 of the Right of Way Statutes which govern the authority to operate within the
- ROW. Including incorporation of language included in the current Labor Agreement with the Alyeska Pipeline Service Company maintenance and construction contractors which has been highly successful in providing career opportunities to Alaskan Natives.
- While the Letter of Intent identifies the intention of the parties to utilize the original TAPS Project Labor Agreement as a template; the parties recognize that the following areas either were originally not recognized or were recognized but not deemed important. The Port Authority intends to craft language to:
    - allow pre-employment drug and alcohol testing;
    - treat safety as a number one priority;
    - allow for background checks;
    - deal with HIRD issues (harassment, intimidation, retaliation, and discrimination); and
    - maximum use of hiring hall procedures to assure that qualified Alaska/local hire is accomplished to the fullest extent possible under law.

8. Alaska Hire

The Port Authority has committed to Alaska hire to the maximum extent permitted by law for the:

(a) Pre-Construction;

(b) Construction;

(c) Start-up;

(d) Operation (30 years);

(e) Maintenance (30 years).

9. Substantial Permitting Progress for the All-Alaska Gas Line

Over a period of sixteen years, the Yukon Pacific Corporation ("**YPC**") obtained required permits for the All-Alaska Gasline. In 2005, the Port Authority acquired an option to purchase YPC and its associated permits and rights-of-way for a gas pipeline from the North Slope to Valdez and for an LNG plant in Valdez.

While some of YPC's data, rights-of-way and permits may need to be updated, their acquisition provides a time advantage associated with the Project. In a prior technical study performed for the Port Authority by Bechtel, it was estimated that access to the YPC permits could save a number of years in developing the Project.

It should be noted that the detailed development and regulatory plans for the Project presented in this Application have been developed without taking into account the benefit of utilizing the YPC option negotiated by the Port Authority. Any time savings associated resulting from the utilization of existing YPC permits and data will provide an improvement above the base timeline for the Project presented herein.

Among YPC documents are included:

1. Presidential Finding: Exports of natural gas from Alaska to nations other than Canada or Mexico require a Presidential finding under the Alaska Natural Gas Transportation Act of 1976, 15 U.S.C. § 719 et seq. ("**ANGTA**"). YPC applied for and received in January 1988 an authorization to export LNG from Valdez. Additionally, in 1988, the U.S. Department of Energy issued an order authorizing the export of gas to Japan, South Korea and Taiwan. This export license is for a period of 25 years for a maximum of 14 mmta. The specified 25 year period starts upon the first shipment of LNG from Valdez. The primary target markets for the Project are currently expected to be these same three countries. The period of time it took to secure this finding was 3 years and 8 months.

2. State of Alaska Coastal Zone Consistency Determination (Tier 1): The original Trans Alaska Gas System ("**TAGS**") project obtained in 1988 a favorable determination that the general project scope was consistent with the standards of the Alaska Coastal Management Program. The period of time it took to obtain this permit was 10 months.

3. Bureau of Land Management/U.S. Army Corps of Engineers TAGS FEIS: The U.S. Bureau of Land Management ("**BLM**") and the Army Corps of Engineers prepared a final environmental impact statement ("**FEIS**") for the TAGS pipeline

project in 1988. The Port Authority plans to update this FEIS. The period of time it took to obtain this permit was 4 years and 5 months.

4. Ahtna Corporation Right-of-Way Agreement: In 1988, the developer of the TAGS project entered into a right-of-way agreement with the Ahtna tribe that sets forth broad terms for the use of right-of-way across Ahtna tribal lands.

5. BLM Right-of-Way Agreement: This right-of-way agreement was also entered into in 1988 which runs parallel to TAPS for from the North Slope to Valdez. The Port Authority intends to update this agreement. The period of time it took to obtain this permit was 4 years and 5 months.

6. State of Alaska Conditional Right-of-Way Lease: As with the BLM right-of-way agreement, the Port Authority intends to update this agreement. This ROW runs parallel to TAPS from Prudhoe Bay to Valdez. The period of time it took to obtain this permit was 2 years and 9 months.

7. Department of Energy Export Authorization: In 1989, the U.S. Department of Energy issued an order authorizing the export of gas to Japan, South Korea, and Taiwan. The Port Authority intends to export gas from its project to these same three countries. The period of time it took to obtain this authorization was 2 years and 11 months.

8. FERC Authorization of Anderson Bay LNG Facility: In 1995, FERC authorized the construction and operation of a LNG facility at Anderson Bay at Valdez. The Port Authority intends to update environmental data for FERC. The period of time it took to obtain this authorization was 7 years and 3 months.

9. Air Quality Construction Permit: The Alaska Department of Environmental Conservation issued in 1997 a permit that allows for air pollutant discharges during construction and operation of the LNG facility. The Port Authority intends to supplement the permit with current and additional data. The period of time it took to obtain this permit was 8 years.

10. Marine Transportation for LNG and NGL

LNG Tanker Transportation

The Project will not own LNG tankers. LNG marine transportation services will be obtained from third parties, under long term time charter arrangements typical in the LNG industry. The providers of marine transportation services will be selected under a competitive tender process.

The Port Authority has developed a relationship with the MOL Companies. MOL is a global leader in marine transportation and has the largest tanker fleet in the world, including crude carriers, product carriers, LNG carriers, LPG carriers and methanol carriers. MOL is a leader in LNG transportation for LNG projects worldwide. MOL and its group of companies own and/or participate in 80 LNG vessels (including 21 vessels under construction), which represents approximately a quarter of the world's existing (or under construction) LNG vessels.

Pursuant to a Teaming Agreement between the Port Authority and the MOL Companies, the Port Authority and the MOL Companies have agreed to work together to develop the marine transportation elements of the Project, including the development of a plan for procurement and implementation of LNG transportation services in structure that is most suitable to the Project.

Pursuant to the Teaming Agreement with the Port Authority, the MOL Companies have provided a cost estimate for marine transportation services based on several options for new-building LNG vessels.

In addition to its relationship with the MOL companies, the Port Authority has also been in discussions with a major Japanese industrial conglomerate, whose business activities include the trading and marketing of LNG and the provision of LNG tanker services. This company has provided to the Port Authority an additional confidential cost estimate for LNG marine transportation for the Project.

The number of LNG tankers required to transport the LNG volumes is primarily a function of: (a) tanker size; and (b) distance to the destination market. The precise fleet configuration for the Project will be determined once the actual sales volumes of LNG to each market in Japan, Korea and/or Taiwan has been finalized, and binding bids under a competitive tender for the provision of marine transportation services have been obtained by the Project. At this time, it is anticipated that the LNG tankers for the Project could range between 147,000 cubic meters ("**m^3**") and 177,000 m^3 class. Vessels in this size range are optimal for the Project in terms of cost and access to East Asian receiving terminals.

Depending on the allocation of offtake LNG volume and the size of vessels selected by the Project, it is anticipated that between 12 and 18 new building vessels would be required to transport the volume of LNG produced.

11. Plan for Canadian Segment

A pipeline to Canada is not proposed for the initial phase of the Project and, therefore, a description of such a project segment is not provided in this Application. However, the Port Authority anticipates that in the future an AlCan Highway pipeline may be implemented and has designed its Project to facilitate and accommodate the development of such a pipeline.

The Port Authority views the All-Alaska Gasline as an initial "enabler" project for ANS natural gas development. The Project will take all available ANS gas not needed for oil reservoir pressure maintenance and other existing uses, and transport it to market in the form of LNG. It is anticipated that at some future point additional ANS gas will become available when it is no longer needed for oil reservoir pressure maintenance and that there will be additional commercial natural gas discoveries that will likely exceed the LNG liquefaction and distribution capabilities of the initial Project.

At that point in time, a likely expansion method for monetizing the full amount of known ANS gas resources and potential future gas discoveries, would be a "build-out" phase which would involve constructing an additional "Y-leg" pipeline from around Delta Junction to deliver these additional gas volumes into Canada along the Alcan Highway for ultimate tie-in to existing pipeline distribution systems delivering gas into Canada and the U.S. Midwest and West Coast markets. The Port Authority is committed to working cooperatively with the sponsor(s) of such a future Canadian pipeline project.

As there are many factors that determine the volume and timing needs for the Canadian pipeline, the Port Authority is not prepared to speculate as to when it might be constructed.

12. Bechtel

Since its formation in 1999, the Port Authority has been working with Bechtel Corporation on the All Alaska gasline project. Bechtel has been engaged in the planning, management, engineering, procurement, and construction of petroleum refineries, chemical and petrochemical plants, gas and liquids pipelines, oil and gas production facilities, and LNG plants for more than 60 years. During that period, Bechtel has successfully completed more than:

- 375 major chemical and petrochemical projects;
- 265 refinery expansions and modernizations;
- 110 gas processing plants;
- 50 major oil and gas field developments (20 offshore, 30 onshore); and
- 85,000 km of pipelines, including oil, natural gas, slurry, multiphase, and refined-product systems in all types of environments.

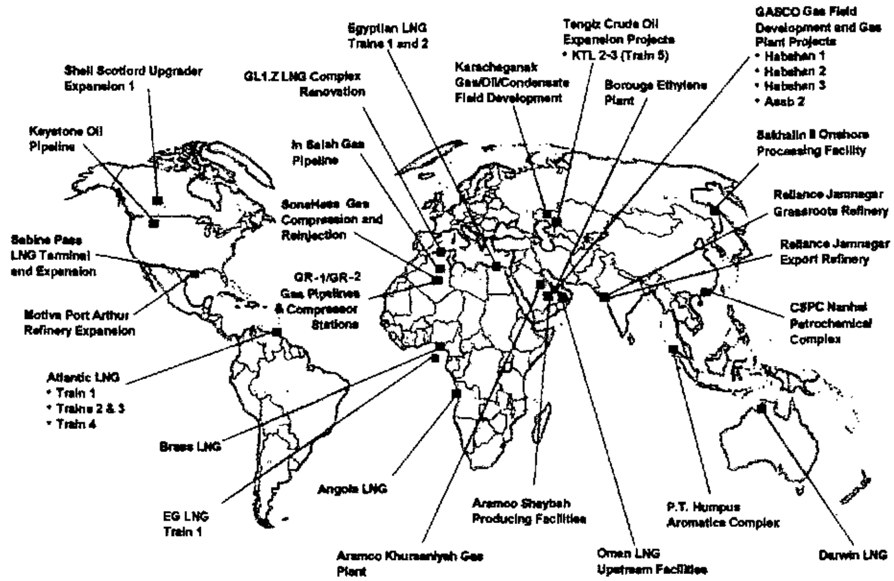
Bechtel has also been responsible for more than 35 percent of the world's current LNG capability, and is moving aggressively to expand our role in advanced energy technologies and alternative fuels.

Bechtel-built facilities encompass virtually every process and material handling technology available. This experience, coupled with long-standing relationships with process licensors, equipment manufacturers, and potential subcontractors, makes Bechtel uniquely qualified to deliver optimum performance, aggressive schedules, low installed cost, and safe design, construction and operation on the largest and most challenging EPC projects. Bechtel's reputation for quality performance and "making the impossible possible" is recognized throughout the industry.

Over the past 10 years, Bechtel has successfully completed more than 50 major projects for customers in the oil, gas, chemical, and pipeline industries. Many of the projects have involved work at remote locations characterized by harsh climatic or environmental conditions. As a result, Bechtel has an in-depth understanding of key execution issues such as provision of logistical support to remote project locations, movement of heavy modules and construction materials, preservation of fragile ecosystems, and maintenance of safe working environments under extremely adverse conditions.

Thirty of the most important projects that Bechtel has executed for customers in the oil, gas, and pipeline industries over the past 10 years are illustrated in Figure 1 below. Each of them has involved the combination of innovative thinking, technical expertise, and proven execution and management systems to meet our customers' cost and schedule goals. Taken together, they demonstrate that Bechtel has the capability to successfully execute major projects in the harshest and most challenging areas on the planet.

Figure 1 Recent Bechtel Oil, Gas, and Pipeline Projects



13. Project Cost Estimate

A summary of estimated Project capital costs, broken down into the principal areas of expenditure, is provided in Table 2 below.

Table 2 Indicative Cost Estimate

Item	Estimated Cost ($ billions)
Development Phase:	
Program Management	**0.070**
Pre-FEED and FEED	**0.185**
Surveys and Permitting Support	**0.120**
Regulatory Agency / Permitting Costs	**0.045**
Owner's Management Costs	**0.105**
Subtotal Development Phase:	*0.525*
Execution Phase:	
Pipeline and Compression Facilities	**11.70**
LNG Facilities	**7.00**
Owners Costs: Pipeline and LNG Facilities	**[2.65]**
Subtotal Execution Phase:	*21.35*
TOTAL:	21.875

14. Former Point Thomson Unit

The Port Authority views commitment of natural gas from the former Point Thomson Unit ("**Point Thomson**") as critical to the success of any midstream project to monetize ANS gas. The Port Authority is of the opinion that the current status of Point Thomson, decreases, rather than increases, Project risks associated with securing firm transportation commitments.

The Port Authority's long held belief that Point Thomson gas is critical to success of its Project efforts has resulted in it being at the forefront of encouraging, and ultimately demanding, development of the field's resources.

In 2004 and the first half of 2005, the Port Authority repeatedly approached the Point Thomson working interest owners, seeking to discuss and negotiate transportation arrangements for gas from the field. It eventually became clear that the former leaseholders were not willing to discuss committing gas to an independent project.

In the fall of 2005, the Port Authority filed extensive factual and legal briefing to DNR, demanding that the State terminate the unit and reclaim the acreage for re-leasing to upstream producers interested in bringing Point Thomson gas resources to market. Since that time, the Port Authority has continued to assist DNR in its efforts to clear title on Point Thomson, including actively participating in the administrate and superior court unit termination proceedings.

The Port Authority's close association with the termination process has left it confident that DNR's efforts will be successful, meaning the State could be in the position to begin the re-leasing process as soon as 2009. Because the Point Thomson reservoirs are largely delineated, and there is little exploration risk associated with the acreage, interest in re-leasing by upstream producers is expected to be strong. Consequently, DNR will be in a position to demand and receive bid terms more favorable than those traditionally received by the State for exploration acreage.

To guarantee maximum ultimate hydrocarbon recovery from Point Thomson, the Port Authority recognizes that gas cycling may be required for a number of years before significant gas offtake from the field is appropriate. Thus the Port Authority commits to immediately begin working with DNR and the AOGCC to establish rules for Point Thomson gas offtake so that the timing of Point Thomson gas availability to the Project can be determined before the Project's initial open season. The Port Authority will also work with the State to embed express "date certain" development commitments into the new leasing arrangements to ensure: (a) cycling, if required by the AOGCC, occurs rapidly, possibly even before Project construction; and (b) Point Thomson gas shipments through the Project are coordinated to maximize recovery in light of Point Thomson and Prudhoe Bay reservoir needs (i.e., Point Thomson gas sales should occur such that total recovery is maximized from both units).

Additionally, the Port Authority believes DNR should take this opportunity to seek a substantially larger share of Point Thomson profits than it has received in the past under its traditional exploration lease arrangements. Structuring the lease sales with royalty or a net profit interest ("**NP**")[5] as one of the key bid variables can be expected to result in a high level of State "take." The Port Authority believes the original Northstar lease sales provide a good analogy for what the State might achieve with Point Thomson.

Northstar is a joint offshore State/federal oil and gas unit located to the north of the Prudhoe Bay unit. In 1979, the Northstar prospect was first put out for bid on a NP bid basis. Four State leases were bid in 1979,[6] and one in 1983,[7] with Amerada Hess and Shell as the primary leaseholders. The four 1979 leases gave the State a one-fifth royalty share plus an 89% NP. The 1983 lease gave the State a one-eighth royalty share plus a 40% NPI, for an average NP on the State's share of the unit of roughly 80%.

Total State "take" can be viewed as the amount of profits on oil and gas the State gets after it collects its royalty share, NP (if any), and severance, property, and state income taxes. For the Northstar leases in the 1980s this can be conservatively estimated at over 90%, assuming: (a) nominal severance taxes because of the later adopted Economic Limit Factor; (b) nominal property taxes (which are small in the total picture); (c) State income taxes of about 9% with an effective rate about half that after deductions; (d) a blended 19% royalty; and (e) a blended 80% NP.

A re-leasing of Point Thomson acreage would share many characteristics with the State Northstar lease sales, including a high oil price environment, but would be more attractive to the lessee because of the lack of exploration risk. Consequently, it is reasonable to assume the State will be able to achieve a similar 90% take for Point Thomson. According to a recent 2007 DOE study this is more than triple the 26.1% take

[5] A net profit interest can be simplistically represented as a share of total lease revenue minus the field development costs (including interest) and State royalty (Net Profit ≈ Gross Revenue – Field Costs – State Royalty). See 11 AAC 83.200-.228.

[6] ADL 312798, ADL 312799, ADL 312808, ADL 312809.

[7] ADL 355001.

(pre-PPT) Alaska would have historically expected ANS-wide after a major gas sale with West Coast oil at $60 per barrel.[8]

The same 2007 DOE study, assuming a flat price of $60 per barrel for ANS crude West Coast prices and ultimate Point Thomson recovery of 7.2 tcf of gas and 390 million barrels of condensates and oil, estimated that the State's total nominal take over the life of Point Thomson under the old lease terms would be approximately $24.3 billion, or a 26.9%.[9] If on re-leasing the State can achieve take percentages comparable to the Northstar leases, i.e., about 90%, the State would expect $81.0 billion over the life of the field given the same pricing, cost and ultimate recovery assumptions.

It can thus be seen that the magnitude of potential economic rents from Point Thomson are significant. If re-leased at anything approaching the NP shares originally received by the State in the Northstar leases, and combined with fixed development timelines, such terms will maximize the economic benefits to the State, while allowing Point Thomson gas, along with Prudhoe Bay gas, to provide the shipping commitments that will anchor the construction of an All-Alaska natural gas pipeline project.

15. Benefits of State Participation in portion of Pipeline Financing

There would be significant financial advantages to both the State of Alaska as well as the potential shippers on the pipeline for the State to participate in a portion of the financing of the gas pipeline. This concept is not without precedent, particularly given the Murkowski administration proposed a 20% minority ownership by the State with a producer owned (Exxon, BP, ConocoPhillips) and controlled pipeline through Canada. A similar proposal now whereby the State of Alaska would participate financially by guaranteeing a portion of the debt (maximum of 30%) of the pipeline would return significant benefits to the State. Those benefits would be as follows:

1. The lower the tariff on the pipeline, the higher the well head price of gas. The State receives the majority of its income and benefit based upon the wellhead value for the gas shipped by North Slope lease holders.

2. The State of Alaska itself presently is the largest North Slope producer, currently controlling 8+ tcf of gas at Point Thomson as well as the gas and royalty share in Prudhoe Bay. A lower pipeline tariff on which the State would ship its own gas would result in a higher well head net back directly to the State.

For years, Alaska has awaited someone to come forth and finance the building of the Trans-Alaska gas pipeline. It is time for the State of Alaska to take a stronger role in the future development of the vast resources of natural gas on the North Slope. The State's participation in a portion of the financing would guarantee a project would be built.

Projects around the world incur different levels of risk. Those risks typically consist of exploration risk and the risks inherent in developing the significant upstream infrastructure required before gas can flow. Alaska is in a converse position. Rather than

---

[8] United States Department of Energy, *Alaska North Slope Oil and Gas - A Promising Future or an Area in Decline?*, Full Report 3-127 (August 2007).

[9] *Id.* at 3-139.

exploration risk, gas is currently re-inject at a volume 2.7 bcf/d in excess of that needed to maintain the pressure on the Prudhoe Bay oil fields. Much of the needed infrastructure is already in place on the North Slope.

State participation in Project financing could be viewed no differently than state involvement in enumerable transportation development projects in our Nation's history such as for canals, railroads, wharfs, airports, etc. For instance, California in the 1960's created the State Water Project, including voters approving bonds in the amount of $1.75 billion (about $12 billion in today's dollars), to allow for the transportation of water in northern California to concentrated population centers in the southern portion of the state. That water aqueduct system consists of approximately 450 miles of concrete-lined canals, underground pipelines, tunnels and channels, with 29 contractors that ship water in this system providing water to approximately 25 million customers. Water is also delivered for irrigation to approximately 75,000 acres of crops within California. However, it is unlikely that the private sector would have been able or willing to provide California with the water transportation infrastructure needed to make it the 7th largest economy worldwide.

It is unlikely that the private sector would have stepped up to provide the California infrastructure needed to move the direly needed water from northern California to the concentration of its population farther south. Similarly, much of Alaska's natural gas resources are located in the northernmost area of Alaska with the population concentration in areas south. Given the price of gas now along with its projected escalation into the future, Alaska can no longer take a back seat position. To continue to wait for companies which are competing globally for investment dollars and access to natural resources to make the commitments needed for Alaska to be able to take Alaska's gas to the world market is foolhardy. It is time for Alaska to step to the plate, cause this pipeline to be built across the state and make our gas available to Alaskans and to the U.S. and global markets.

16. Project Partners

To date, the Port Authority has a long-standing relationship with the Bechtel Corporation, much of whose data is presented in the Port Authority's application. Bechtel is clearly a world-renowned leader in projects of this magnitude given its 60-plus years of expertise in this area. Additionally, the Port Authority has entered into a Teaming Agreement with Mitsui O.S.K. Lines (MOL), one of the world's largest carriers of LNG to participate in the shipping of LNG from Alaska. MOL, though an affiliate, has ownership of eight U.S. built LNG tankers that upon reflagging, would be available for service from Alaska into the Lower 48 market. The Port Authority has received letters of interest from two other companies who are significant participants in the LNG business who have at this time requested that their names remain confidential. As this process moves forward, we look forward to presenting those companies to the public. The names and details of the relationship with those entities have been made available on a confidential basis to the State through the AGIA process.

Additionally, we have been in contact with a number of significant world-wide participants in the LNG business who have expressed their support for our Project and have requested further discussions with them following the public release of all applications.

The reception we have received to date from companies looking at this project has been very positive based largely upon the economics of our Project, the proven reserves at the North Slope and the stability of government that Alaska provides.

Application for the All-Alaska Gas Line Project

Submitted by the Alaska Gasline Port Authority

to the State of Alaska Department of Revenue

for the Issuance of a License

Pursuant to the Alaska Gasline Inducement Act (AS 43.90)

(Including requested clarifying information)

November 30, 2007

Alaska Gasline Port Authority
411 4th Avenue
Fairbanks, Alaska 99701
(907) 278-7000

Table of Contents

List of Figures

List of Tables

List of Appendices

Appendix Z	**Trans-Alaska Gas System (TAGS) 42 inch Right-of-Way Modifications, Submissions to Joint Pipeline Coordinator's Office (JPO), October 15, 1992**
Appendix AA	**Valdez Coastal Management Program, Resource Maps, December 1984**
Appendix BB	**Application to U. S. Department of Energy for Authorization to Export Liquefied Natural Gas**
Appendix CC	**Route map for proposed 36" OD. Pipeline [Confidential]**
Appendix DD	**Compressor Station A map, over-size drawing. [Confidential]**
Appendix EE	**Compressor Stations for proposed 36" O.D. pipeline [Confidential]**
Appendix FF	**Yukon River Bridge plans/drawings [Confidential]**
Appendix GG	**LNG Terminal Design/Plan Drawing – 1 page sample [Confidential]**
Appendix HH	**FERC letter granting extension of time to commence construction of Anderson Bay LNG export facilities, May 18, 2007**
Appendix II	**Drawing/Plans showing bore hole locations for Anderson Bay LNG Terminal (over-size drawing)[Confidential]**
Appendix JJ	**Anderson Bay LNG Plant and Terminal Site, Grid Layout with preliminary borehole and trench locations (over-size drawing) [Confidential]**
Appendix KK	**Pipeline drawing showing pipeline location at elevation along Atigun River and Atigun Camp. [Confidential]**
Appendix LL	**AOGCC Report re Rule 9, July 10, 2007**
Appendix MM	**Project Labor Agreement**
Appendix NN	**AGPA Financial Model (Excel Spreadsheet) [Confidential]**
Appendix OO	**Regulatory Plan**
Appendix PP	**Project Execution Plan**
Appendix QQ	**Environmental Management Plan**
Appendix RR	**Letter of Interest [Confidential]**

1. Introduction and Summary Project Description

1.1 The Alaska Gasline Port Authority

The Alaska Gasline Port Authority ("**Port Authority**") is a municipal port authority established on October 5, 1999, in accordance with the Alaska Municipal Port Authority Act, AS 29.35.600 et seq., which allows for the creation of municipal port authorities to "provide for the development of a port or ports for transportation related commerce within the territory of the authority."

The Port Authority was formed by the municipalities of the North Slope Borough, Fairbanks North Star Borough and the City of Valdez to develop, build or cause to be built, finance, and operate or cause to be operated a project to monetize Alaska's North Slope natural gas, which would include a trans-Alaska gas pipeline, liquefaction and gas processing facilities and related infrastructure for the transportation of North Slope natural gas to market ("**Project**" or the "**All-Alaska Gasline**").

The Port Authority is submitting this application ("**Application**") to the Alaska Department of Revenue for the issuance of a license pursuant to the Alaska Gasline Inducement Act, AS 43.90.010 et seq. ("**AGIA**"). The Application has been prepared in response to the Request for Applications ("**RFA**") issued by the State of Alaska ("**State**") on July 2, 2007, as subsequently amended. The Port Authority hereby requests the award of a license pursuant to AGIA ("**License**"), enabling the Port Authority and its Project to benefit from the project inducements enumerated in AS 43.90.110. The Port Authority also waives the right to appeal the rejection of this Application as incomplete, the issuance of a License to another applicant, or the determination under AS 43.90.180(b) that no application merits the issuance of a License.

1.2 The Project

The Port Authority's Project consists of the components described below.

1.2.1 Pipeline

The Project will include an 806-mile overland natural gas pipeline extending from Prudhoe Bay to tidewater at Valdez ("**Pipeline**"), which will run parallel to the existing Trans-Alaska Pipeline System ("**TAPS**"). This will be a dense-phase pipeline, designed to transport Alaska North Slope ("**ANS**") natural gas, which contains a relatively high amount of natural gas liquids ("**NGLs**"). The proposed initial capacity of the Pipeline is approximately 2.7 billion cubic feet per day ("**bcfd**") of natural gas at the Pipeline inlet in Prudhoe Bay. The Pipeline will be capable of rapid capacity expansion through the addition of compression facilities.

The Pipeline will transport ANS natural gas to (i) Valdez for liquids extraction and liquefaction prior to shipping to export markets and (ii) in-State delivery points for meeting local Alaska consumer and commercial needs. The Port Authority anticipates that a delivery point at Glennallen would provide natural gas for a spur line to Palmer that would tie into the South Central gas grid as proposed by the Alaska Natural Gas Development Authority ("**ANGDA**").

The Pipeline will be designed to allow a future tie-in at Delta Junction (550 miles south of Prudhoe Bay) for a later spur line from Delta Junction to the Alaska/Canadian border, following the Alaska-Canada "(**Alcan**") Highway. Although the Port Authority is not actively pursuing the development of such a project at this time, it is committed to working cooperatively with the sponsor(s) of such a project to maximize the options for monetizing ANS natural gas.

1.2.2 Liquefaction and Liquids Extraction Facilities

The Project will include an integrated liquefaction and fractionation facility in Valdez which will: (a) extract the propane and butane (liquid petroleum gases or "**LPGs**"), from the gas transported through the Pipeline; and (b) produce liquefied natural gas ("**LNG**") using three process trains, each with nominal design capacity of approximately five million metric tons per annum ("**mmta**"), for a total LNG production capacity of 15 mmta. The LNG will be exported to Asian markets in Japan, South Korea and Taiwan or North America. Also included are storage and vessel loading facilities for LNG and LPGs (together with the liquefaction and fractionation facilities, the "**LNG Facilities**").

1.2.3 Project Components to be Developed by Third Party Entities

1.2.3.1 Gas Conditioning Plant

For the purposes of this Application, it has been assumed a gas conditioning plant ("**GCP**") will be built, owned and operated by other entities at Prudhoe Bay to remove carbon dioxide, water, and trace amounts of hydrogen sulfide from the natural gas feed and to compress and chill the gas to pipeline specifications. The GCP will also be capable of extracting heavier (pentanes+) NGLs, which will be blended into the TAPS stream.

Gas conditioning and treatment services at the GCP are assumed to be provided to the Project on a third-party basis pursuant to commercial arrangements which will be negotiated during the development phase of the Project. Therefore, this Application does not include a detailed technical description of the GCP in the Project scope.

1.2.3.2 *Marine Transportation Services for LNG and NGL*

The Project will not own LNG tankers. LNG marine transportation services will be obtained from third parties, under long term time charter arrangements typical in the LNG industry. The providers of marine transportation services will be selected under a competitive tender process.

The Port Authority has developed a relationship with Mitsui O.S.K Lines, Ltd. ("**MOL**") and its subsidiaries BGT Limited and BLNG Inc (together with MOL, the "**MOL Companies**"). MOL is a global leader in marine transportation and has the largest tanker fleet in the world, including crude carriers, product carriers, LNG carriers, LPG carriers and methanol carriers. The Port Authority and the MOL Companies have agreed to work together under a Teaming Agreement to develop the marine transportation elements of the Project, including the development of a plan for procurement and implementation of LNG transportation services in structure that is most suitable to the Project. For the purposes of this Application, the MOL Companies have provided a confidential cost estimate for marine transportation services based on several options for new-building LNG vessels.

NGL marine transportation services will similarly be obtained from third parties pursuant to a competitive tender process. The Port Authority and the MOL Companies have agreed to work together to develop the LPG tanker transportation framework for the Project.

1.2.4 Target Markets for Alaska's Gas

The principal target markets for the Project LNG and NGL are the Pacific Rim markets, specifically the major LNG consuming countries of Japan, South Korea and Taiwan. It is expected that the Project, as currently envisioned, would provide an attractive economic proposition to ANS gas producers participating in the open season, due to the premium pricing available in these markets.

While East Asian constitutes the principal target gas market at this time, the Port Authority has structured the Project in a manner to facilitate access to U.S. and other North American gas markets as well. The Project's increased pipeline diameter from Prudhoe Bay to Delta Junction is sufficient to be considered as the "pre-build" of the first 550 miles of the proposed Alcan Highway project.

Additionally, the Port Authority is a participant in the open season being held by Sempra LNG for the expansion of the soon to be completed Energia Costa Azul regasification terminal in Mexico, just south of San Diego, California. This facility is at present the only receiving terminal on the West Coast of North America. The Port Authority has also received a letter of support from the only other fully permitted West Coast LNG receiving terminal, located in Kitimat, British Columbia, which would provide access to gas markets on the West Coast or in the Midwest via existing Canadian pipeline infrastructure.

Should a prospective shipper of Alaska gas be interested in accessing North American gas markets through either of these West Coast terminals, the Port Authority would work under its Teaming Agreement with BGT and its parent company MOL, to provide a cost-effective marine transportation solution in compliance with the Jones Act. BGT currently controls a fleet of eight U.S.-built LNG tankers that, following reflagging, would be available to serve gas transportation to domestic markets.

1.3 Engineering and Technical Work by Bechtel

Engineering design, cost estimation, and other technical work in connection with this Application has been performed for the Port Authority by the Bechtel Corporation

("**Bechtel**"). While the definitive selection of project management and engineering, procurement and construction ("**EPC**") contractors for the Project will be performed during the development phase, it is expected that Bechtel will perform a significant role in the Project's construction.

Cost estimates provided herein have been revised in November of 2007 and have been used to obtain an up-to-date forecast of the Project's economics.

1.4 Significant Advantages of the All-Alaska Gasline Project

1.4.1 Superior Economics

1.4.1.1 Premium LNG Markets

The Project will allow the value of ANS natural gas to be maximized by providing access to global LNG markets.

Historically, Asian markets have received their natural gas supplies in the form of LNG, under long term supply contracts with LNG prices tied to the price of oil. Many of those contracts are approaching the end of their initial terms and must be renewed. Current market developments have put an upward pressure on the prices for LNG supplied to the East Asian markets. Recently negotiated LNG supply contracts have included revised oil price indexation provisions, resulting in LNG prices close to thermal parity with oil prices.

It is expected that future LNG supply contracts to the Asian markets will retain these pricing features, resulting in prices significantly higher than forecast North American gas prices. According to the Institute of Energy Economics, Japan ("**IEEJ**"), Asian LNG prices are expected to be in the range of 80 to 90 percent of the price of crude oil, which would result in an average premium of approximately $3.00 per million British thermal units ("**mmBtu**") over projected Henry Hub gas prices.

1.4.1.2 Higher Netback Value for Alaska and ANS Producers

Premium prices of LNG, coupled with competitive cost of transportation to the target markets, result in projected superior netback values in comparison with alternative ANS gas transportation proposals, such as a pipeline to Canada. The Project, therefore, would achieve higher returns for the ANS producers of natural gas and higher revenue for Alaska from royalties and production tax on gas.

With the All-Alaska Gasline Project, higher netback values are achieved even with smaller gas volumes than those proposed for other ANS gas transportation projects. The total reserve requirements for the Project are within the existing discovered resource base, resulting in a high degree of confidence that sufficient gas supply commitments would be obtained under the initial open season for the Project.

Table 1 Projected 20-year Average Netback Prices for the All-Alaska Gasline and Alcan Highway Projects

	LNG Base Case (2.7 bcfd)	Alcan 3.0 bcfd	Alcan 4.5 bcfd
Average Netback Price at Point of Produciton ($ / mmBtu)	5.43	3.42	4.33
30-Year Reserve Requirements (Tcf)	30	34	51

The All-Alaska Gasline Project enjoys a netback pricing advantage ranging from $1.10 to $2.00 per $mmBtu, depending on the gas volume assumptions, resulting in a significant competitive advantage over the proposed Alcan Highway line. Higher netback prices are achieved on the basis of smaller volume and, therefore, smaller reserve requirements to support the Project.

1.4.1.3 Market Optionality

Although at the present time it is assumed that LNG volumes will be marketed in East Asia, the Project would allow Alaska and its gas producers to access gas markets worldwide, including gas markets in the Lower 48 United States, and capture the highest possible sales value for gas, including premiums associated with seasonal and other natural gas market variations. Such alternative gas markets can be reached (a) directly through the supply of the Project's own LNG, or (b) through swap or similar arrangements, which are becoming increasingly common in the global LNG industry. The All-Alaska Gasline provides the only way for Alaska to participate in the global gas commodity market of the future.

1.4.2 Substantial Permitting Progress for the All-Alaska Gas Line

Over sixteen years, the Yukon Pacific Corporation ("**YPC**") obtained required permits for the All-Alaska Gasline. In 2005, the Port Authority acquired an option to purchase YPC and its associated permits and rights-of-way for a gas pipeline from the North Slope to Valdez and for an LNG plant in Valdez.

While YPC's data, rights-of-way and permits will need to be updated, their acquisition provides a time advantage associated with the Project. In a prior technical study performed for the Port Authority by Bechtel, it was estimated that access to the YPC permits could save a number of years in developing the Project.

It should be noted that the detailed development and regulatory plans for the Project presented in this Application have been developed without taking into account the benefit of utilizing the YPC option negotiated by the Port Authority. Any time savings associated resulting from the utilization of existing YPC permits and data will provide an improvement above the base timeline for the Project presented herein.

1.4.3 Right Sized, Right Now!

Given the volumes of gas needed are within the currently allowable offtake limits for Prudhoe Bay and the YPC permitting already done, the All-Alaska gasline project can make ANS gas available to Alaskans sooner than any other proposed project.

1.5 Background on the Port Authority

1.5.1 Formation and History

In the United States, there is a long history of creating governmental organizations to promote and develop projects that the private sector is either unwilling or unable to undertake. There are approximately 160 port authorities nationwide. They range in size, with the largest port authority having an operating budget in 2007 of nearly $6 billion. In 1992 legislation was enacted in Alaska, the Alaska Municipal Port Authority Act, AS 29.35.600 et seq., which allows for the creation of municipal port authorities.

To enable municipalities to promote and develop projects that the private sector is either unable or unwilling to undertake, Alaska law allows for the creation of municipal port authorities for the express purpose of "provid[ing] for the development of a port or ports for transportation related commerce within the territory of the authority." AS 29.35.730(5) broadly defines "port" as a "facility of transportation related commerce located within the state."

In 1999, in an effort to overcome perceived economic hurdles associated with an ANS natural gas pipeline project, the voters of the City of Valdez, the Fairbanks North Star Borough and the North Slope Borough decided, by a collective approval of approximately 80 percent, to create the Alaska Gasline Port Authority, with the directive to "build or cause to be built a natural gas pipeline from facilities in the Prudhoe Bay area on the North Slope of Alaska … to Valdez"; to make gas available to Alaska consumers and to share the net revenues statewide from the Project. Immediately following the vote, the municipalities responded to the mandate and passed parallel ordinances establishing the Port Authority.

1.5.2 Objectives of the Alaska Gasline Port Authority

Guided by the mandates of the Statehood Compact, the Alaska State Constitution, and Alaska Statutes, the Port Authority has developed the All-Alaska Gasline Project not only to fulfill the goals and requirements of AGIA, but to provide maximum benefits to Alaska.

Perhaps the most important characteristic of the Project's structure is that, as a public entity, the Port Authority is not driven by the need to maximize its profits, but to provide "maximum benefit" to the people of the State of Alaska. In contrast to entities with natural gas development projects elsewhere in the world that compete internally for corporate investment funds, the Port Authority was formed to advance a single project that is completely within Alaska.

Since its inception, the Port Authority has worked to apply the unique structure of a public/private participation to a natural gas pipeline project with the aim of significantly improving the economic viability and, thus, the likelihood of success of bringing ANS natural gas to Alaskan consumers and the market. This structure enables the Port Authority to have a singular focus on its mission to:

- enable the development of ANS gas to the maximum benefit of all Alaskans, including the distribution of net project revenues;
- promote Alaska hire throughout construction and operation;
- provide access to gas for existing and additional in state petrochemical industries;
- provide for maximum distribution of Alaska's natural gas throughout the State;
- bring ANS natural gas to markets at long-term competitive prices; and
- bring the benefits of a tax-exempt structure to an ANS gas pipeline project.

Throughout the development of the Project, the Port Authority has enlisted the participation of world leaders in the development of large-scale oil and gas projects for expert advice in the areas of: engineering and design, cost estimation, economic modeling, LNG shipping, and LNG and NGL marketing.

As an Alaskan entity, the Port Authority has designed the Project with the intent of maximizing the benefits to the State of Alaska, while providing attractive returns to the ANS gas producers. The Project offers the following key benefits to Alaskans.

- The Port Authority's goal is to provide maximum availability of reasonably priced pipeline transportation of ANS natural gas and NGLs for Alaskan needs. To that end, the Port Authority is committed to working with the State, should it choose to make available State royalty gas to Alaskans at a price not tied to a Lower 48 gas hub price.
- A non-producer owned pipeline will provide for maximum competition in the development of ANS gas. As a non-producer, publicly-owned entity engaged in natural gas transportation, the Port Authority is not driven to maximize its profits through the pipeline transportation tariff, and will therefore create the most competitive opportunity for additional exploration and development of ANS gas.
- The Port Authority's proposal ensures the earliest development of a transportation project for monetizing ANS gas. The Port Authority has obtained the exclusive rights to utilize existing State and Federal permits and authorizations supporting the Project and is committed to moving forward with project development immediately. The Port Authority has no interest in other project development efforts worldwide and, therefore, is not conflicted over where it will invest money and efforts.
- The Project enjoys strong economics.
- The Project would provide for the highest net present value ("NPV") of cash flows to the State of Alaska because (a) it provides ANS producers with access to premium gas markets resulting in strong netback prices; and (b) development can commence sooner than competing proposals.

- All of the Project's pre-construction, construction, start-up, operation, maintenance and value-added jobs will be located within Alaska.
- Because of its proposed initial size of 2.7 bcfd, the Project has the highest probability of a successful open season because: (i) the proposed initial volume is within the current gas offtake allowance by the Alaska Oil and Gas Conservation Commission ("**AOGCC**") for the Prudhoe Bay Unit ("**PBU**"); and (ii) the Project is economically viable at such lower initial volumes and, therefore, does not require the discovery of additional ANS proven gas reserves prior to the initial open season that would be required to support a larger capacity pipeline.
- The implementation of non-producer owned Pipeline that is capable of rapid expansion will provide a strong incentive for present and future ANS explorers to discover, develop and market new gas reserves.

1.5.3 *Over Thirty Years of Public Support for the All-Alaska Gasline Project*

The All-Alaska Gasline has consistently been the preferred project of Alaskans statewide. The overwhelmingly supportive votes that created the Port Authority in 1999 and ANGDA in 2002 (ballot language specifically referring to a gas pipeline from the North Slope to Valdez) are only two examples of Alaskans' strong preference for the All-Alaska Gasline.

Dating back as far as the mid 1970's, Alaskans have made it clear that they prefer an All-Alaska Gasline route over a trans-Canadian route:

> Questionnaire Result:
>
> "Dear Fellow Alaskans:
>
> I want to thank all of you who responded to the questionnaire which appeared in the December, 1975, issue of the newsletter.
>
> I received approximately 45,000 responses as of the first of February. The following are the results which are tabulated from the responses received.
>
> Do you support a trans-Alaska gas pipeline as opposed to a trans-Canadian line?
>
> Yes – 85% / No – 8% / Undecided – 9%"
>
> -Senator Ted Stevens
> Newsletter
> December, 1975

There have been numerous resolutions passed by individual communities and the Alaska Municipal League ("**AML**") in support of the Port Authority's All Alaska Gasline project. Such community and AML resolutions are attached in Appendices D and E.

In May 2005, when then Governor Frank Murkowski was negotiating exclusively for a producer-owned gas pipeline project through Canada, two public opinion polls were conducted that focused on what Alaskans understood and felt about issues surrounding the development of a ANS natural gas transportation project. Dave Dittman of Dittman Research Corp. conducted an "Alaska Poll" that asked Alaskans the following question:

> "At the present time, there appear to be three different proposals to bring Alaska's North Slope natural gas to market. A company named TransCanada, which says it already has all the Canadian permits needed to build a pipeline from the North Slope through Canada to the Mid-Western United States. A combined proposal by ConocoPhillips, BP and Exxon – who have leased the rights to Alaska's North Slope gas – they would also build a pipeline from the North Slope through Canada to the Mid-Western United States. And a proposal by the Alaska Gasline Port Authority to build a pipeline from the North Slope to Valdez, where the gas would be liquefied and transported to market by tankers.
>
> Just based on that information, which proposal do you think the state should select?"

The results of the poll indicated that the majority of Alaskans from every regional, political, age and gender demographic believed the State should select the proposal of the Port Authority for an All-Alaska Gasline. The poll results are attached in Appendix F.

Around that same time, the Port Authority hired Jean Craciun of CRG Research to poll Alaskans about their understanding of the ownership issues surrounding Alaska's natural gas and their preferences on how it should be developed. The results of that poll showed that 77 percent of the persons polled understood that it is the State that owns the gas resources and 62 percent favored the All Alaska Gasline as the project that they "would most like to see happen". The poll results are attached in Appendix F-1.

As recently as November 25, 2007, former Governor Walter Hickel provided an unsolicited endorsement of the All-Alaska Gasline and the Port Authority's Application:

> "I am rooting for the Alaska Gasline Port Authority, a consortium of three communities located along the oil pipeline route. I am not privy to their plans or their proposal, but their leadership is outstanding, and they want to build an All-Alaska LNG system, the concept I believe in."
>
> "I support an all-Alaska gas line from Prudhoe Bay to Valdez for the following reasons: a much sooner start up time, more revenue for the state and municipalities, guaranteed access to the gas by Alaskans, value-added jobs that will last generations and flexible markets for our LNG."
>
> Governor Walter Hickel
> "We Alaskans can build our own gas line"
> Comment, Anchorage Daily News
> November 25, 2007

2. Plan for the Project

2.1 Project Description

This section of the Application describes each Project component, as required in RFA section 2.1.

2.1.1 Pipeline Design

2.1.1.1 Overview

The Pipeline will initially transport the gas requirement for 15 mmta of LNG, which is approximately equal to 2.7 bcfd of conditioned natural gas, over a distance of 806 miles from the ANS to the LNG Facilities in Valdez, Alaska.

The gas at the Pipeline inlet, as conditioned at the GCP, is assumed to be free of moisture, carbon dioxide, and mercury (see Table 2 below). It is assumed to be at a pressure of 2220 psi and chilled to 28°F prior to entering the Pipeline. The estimate presented in Table 2 is based on the "lean gas case" indicative gas composition provided on page 15 of the RFA, as adjusted to take into account the reduced carbon dioxide levels assumed for the Project. The RFA also provides a "rich gas" composition scenario. The impacts on the Pipeline and/or compression stations' capacity or design of using the "rich gas" scenario are minimal and as such they have not been addressed in the cost estimate provided in this Application. Such alternative gas composition scenarios will be evaluated further during front end engineering design ("**FEED**").

Table 2 Gas Conditions to the Inlet of the Pipeline

Pressure	2220 psig
Temperature	28 °F
Lean Gas Composition	
Methane	91.27 %Mol
Ethane	5.88 %Mol
Propane	1.72 %Mol
i-Butane	0.10 %Mol
n-Butane	0.20 %Mol
C5+	0.10 %Mol
Nitrogen	0.71 %Mol
H2S	0.00 %Mol
H20	0.00 %Mol
CO2	100 ppm
Mercury	0.00 %Mol
Mercury	0.00 %Mol

Compressor station locations are defined to support the initial Pipeline capacity, but also to allow the facilities to be expanded in an efficient manner to accommodate additional throughput in the future. Compressor station spacing and design will also consider gas chilling requirements to protect against permafrost degradation in downstream pipeline segments.

The Pipeline begins at the ANS and will receive pipeline quality gas at 2220 psig and 28°F. Along with intermediate compressor stations and up to the inlet of the slug catcher at the LNG Facilities, these conditions match the compression requirement of the Pipeline. Sufficient compression will be installed initially to transport the initial gas flow. The use of aero-derivative gas turbine drivers will be considered with a view to minimizing emissions and complying with applicable emission limits. It is envisioned that common designs will be used across all sites to enable sparing to be optimized. Although a stand-by turbine-driven compressor will be included at the head compressor station on the North Slope, this will not be repeated at the intermediate compressor stations. However, a capital spare has been included in the cost estimate. During outage of either of the intermediate compressor stations, flow is maintained to the LNG Facilities through line pack which will ultimately fall to around 1.4 bcfd, i.e., the maximum flow with only one out of the two installed compressors operating at either of the two intermediate compressor stations.

Compressor station sites not needed for the initial flow condition will be equipped with scraper traps, and valves for station bypass and isolation. Gas offtake points will be provided for potential processing and sales of gas or product (by others). An offtake point at Delta Junction will be 48" in diameter to facilitate future expansion of the system to interconnect with a pipeline to the Canadian border.

With the addition of further compression, the ultimate theoretical capacity of the system is estimated to be approximately 5.4 bcfd to Valdez.

To avoid soil instability associated with melting permafrost, gas from the compressor discharge will be cooled to 28°F. In winter, when the ambient air temperature is 20°F or lower, air-cooled heat exchangers (coolers) will be employed to cool the gas. When ambient air temperatures are higher than 20°F, refrigeration systems, utilizing propane as refrigerant, will be employed. Coolers will have 25 percent spare capacity (one standby spare bay for every four operating bays). Each refrigeration system will include one spare turbine-driven compressor, and 25 percent spare air-cooled heat exchangers (propane coolers).

Turbine-driven generators will provide electric power at all compressor stations. Potable water and firewater will be stored on site in a fresh water storage tank. Other required utilities, including compressed air, and sanitary sewage treatment, will also be provided on site. Waste heat from the generator units' exhaust will be recovered for space heating.

The Pipeline scope will include 37 mainline block valve stations. Each station will consist of a mainline block valve, equalization bypass, vent valves, and vent stack. Valves will be operated by electro-hydraulic actuators. Electric power for the actuators, for systems control and data acquisition ("**SCADA**") equipment, for space heating, and for fuel gas heating will be generated on-site by an engine-driven generator.

2.1.1.2 Pipeline Design Basis

Table 3 Pipeline Design Basis

Parameter	Units	Value
Pipeline Length	Miles	806
Pipeline Diameter:		
• Prudhoe Bay to Delta Junction (550 miles)	Inch	48
• Delta Junction to Valdez (256 miles)	Inch	42
Linepipe Grade		API 5LX80
Maximum Allowable Operating Pressure (MAOP)	Psig	2220
Minimum Delivery Pressure at the Intermediate Compressor Stations (to avoid hydrate formation)	Psig	1150
Minimum Delivery Pressure to the LNG Facility	Psig	1300
Pipeline Design Code		ANSI B31.8
Maximum Design Factor		0.72
Corrosion Allowance		Nil
Absolute Roughness	Inch	0 .00035

A preliminary pipeline hydraulic analysis was carried out using Gregg Engineering's WinFlo proprietary simulation software. The results are presented in the figures below. *Figure 1 and Figure 2 represent the base 2.7 bcfd case and Figure 3 and Figure 4* represent a theoretical maximum capacity case of 5.4 bcfd to Valdez. During FEED further analysis will be carried out to develop and optimize the system design.

Figure 1 **Pressure Profile: 3 Compressor System -- Lean Gas 2007 (Winter)**
Flow Rate: 2.7 bcfd

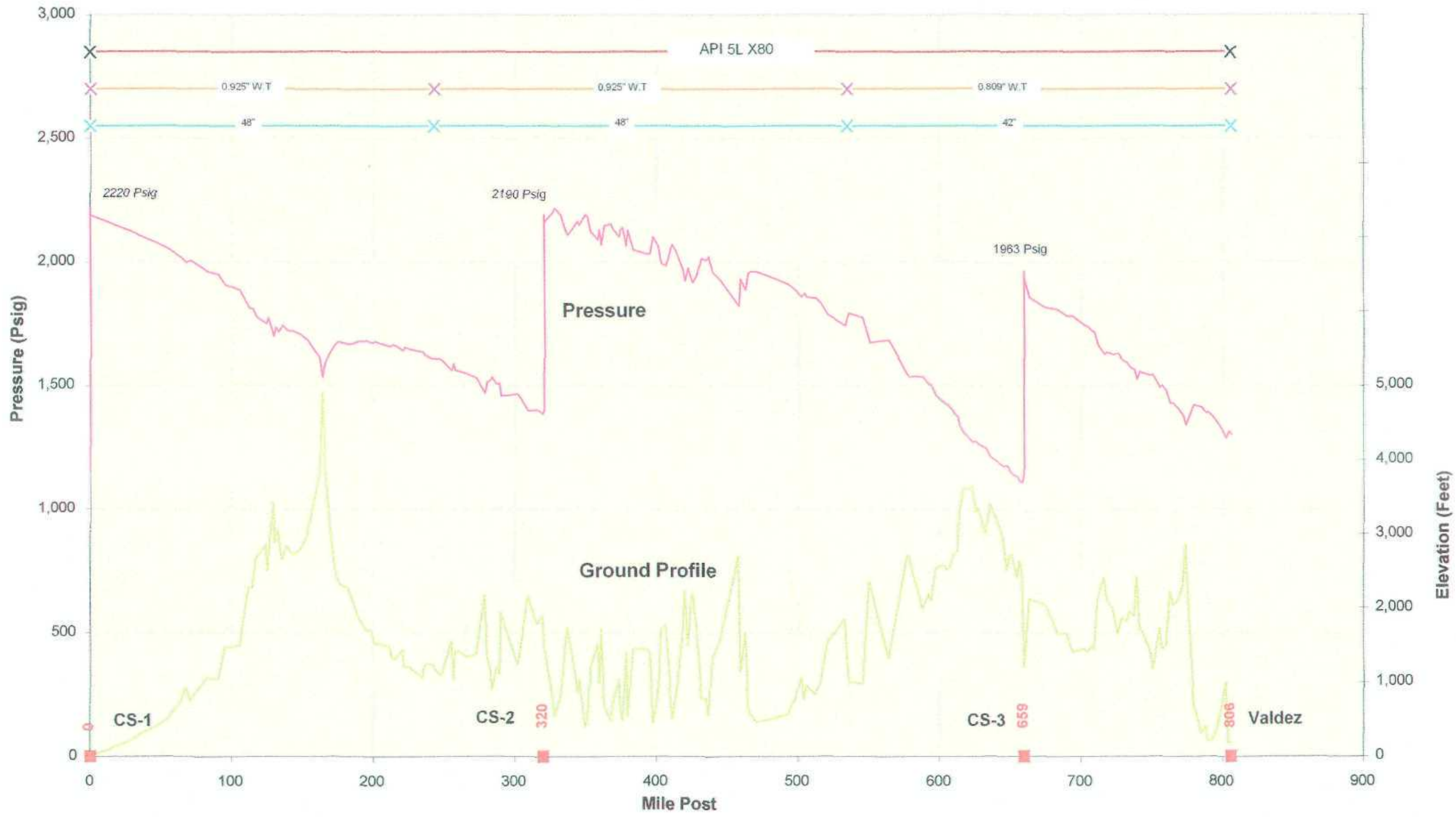


Figure 2 **Temperature Profile: 3 Compressor System – Lean Gas 2007 (Winter)**
Flow Rate: 2.7 bcfd

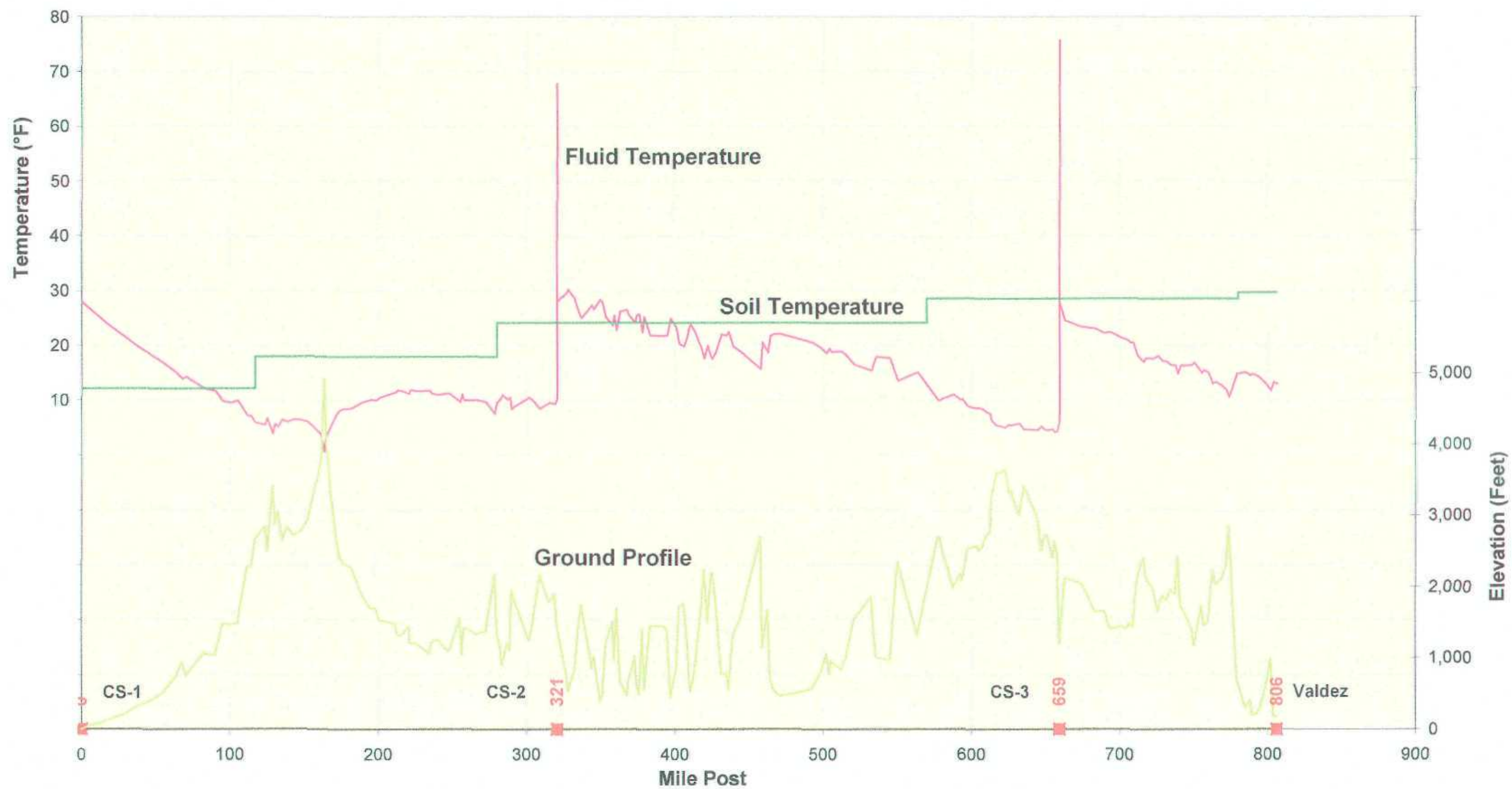


Figure 3 **5.4 bfd 48-inch Pressure Profile**
5400 mmscfd at Valdez, 2200 Psig – Lean Gas 2007 (Winter): 48 Inch – 48 Inch Case
Flow Rate: 5.989 bcfd at Pipeline Inlet, Delivery Pressure 1250 Psig

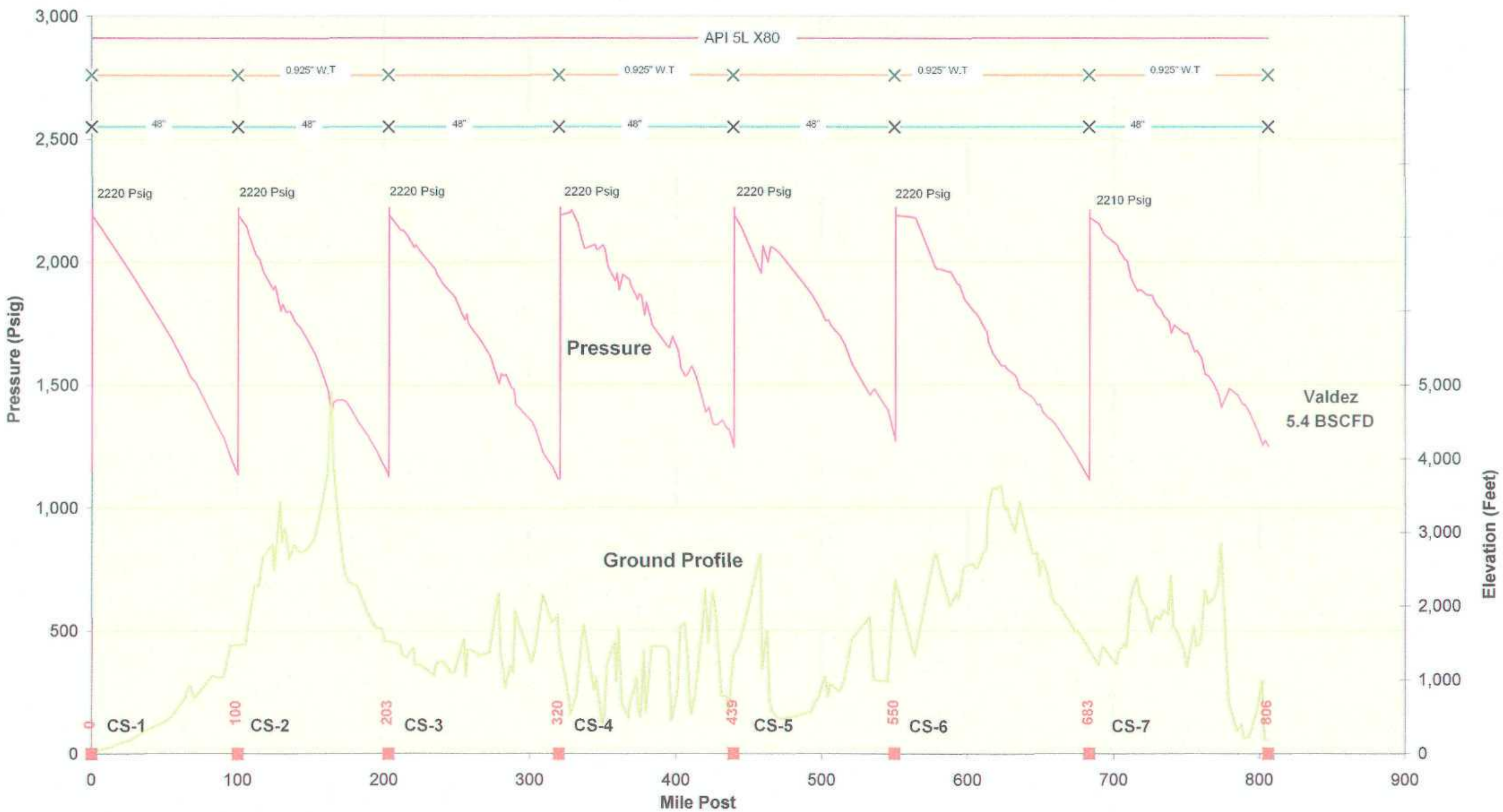
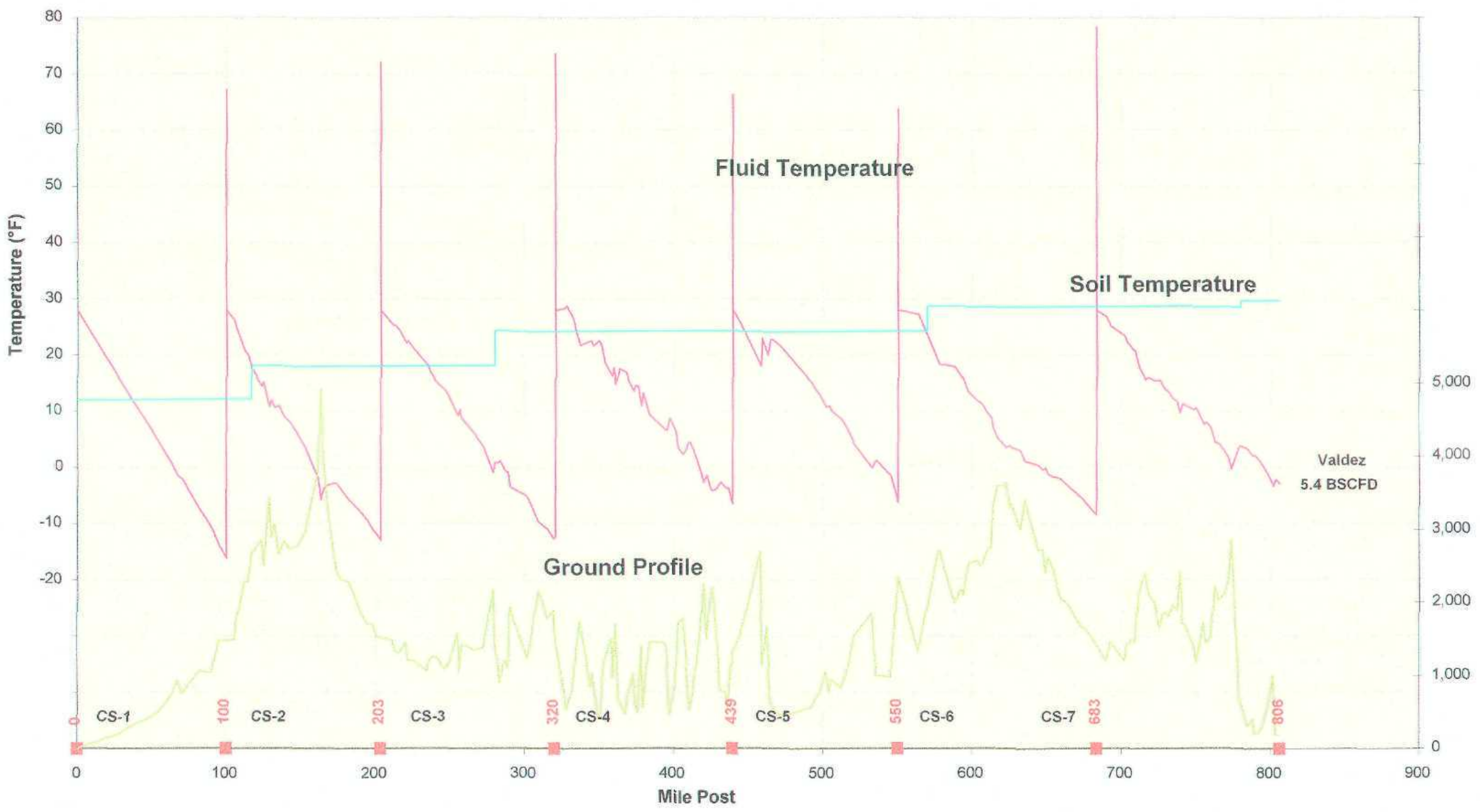


Figure 4 **5.4 bfd 48-inch Temperature Profile**
5400 mmscfd at Valdez, 2200 Psig – Lean Gas 2007 (Winter): 48 Inch – 48 Inch Case
Flow Rate: 5.989 bcfd at Pipeline Inlet, Delivery Pressure 1250 Psig



2.1.1.3 Pipeline Route

The Pipeline route begins at Prudhoe Bay and runs south to Valdez parallel and adjacent to TAPS in the gas pipeline corridor identified in the Federal Right-of-Way ("**ROW**") Grant issued to YPC on October 17, 1988 and in the State of Alaska Conditional ROW Lease issued to YPC on December 10, 1988.

Pipeline Alignment Sheets, dated June 20, 2003, which show the Pipeline alignment within the existing permitted gas pipeline corridor, are provided in the confidential Appendix I.

2.1.1.4 Pipeline Receipt and Delivery Points, Major Markets Served

The Pipeline will deliver ANS natural gas to Valdez for liquefaction and liquids extraction at the LNG Facilities. The Pipeline will also deliver ANS gas to delivery points along its route to serve in-State demand for natural gas. See Section 2.2.3.9 below for a detailed discussion of potential in-State natural gas consumption centers.

2.1.1.4(a) Importance of Gas Supply to South Central Alaska

Gas production in the Cook Inlet is forecasted to fall sharply over the next few years. In June of 2004, a U.S. Department of Energy ("**DOE**") study projected a 75% drop in production from over 200 bcf per year in 2005 to less than 50 bcf per year by 2014.[1] The Alaska Department of Natural Resources ("**DNR**") most recent annual report was slightly more optimistic, estimating Cook Inlet gas production to reach 52.7 bcf per year in 2017.[2]

The impact of this reduction will be dramatic. As supply constricts, medium-term South Central Alaska gas prices will rise significantly, meaning Alaskan consumers can expect increased gas and power utility rates. Reductions in base supply have already begun to directly affect industrial users.

Agrium, which consumes natural gas for the production of urea, was the first industry to suffer from such reductions. Agrium shut down its Nikiski plant in the winter of 2006-2007 so gas could be made available for higher priority home heating. In September of this year, Agrium closed its Kenai fertilizer facility, laying off more than 100 employees.

The Tesoro petroleum refinery at Nikiski which began operations in 1969, processes oil produced from Cook Inlet. It normally uses natural gas as fuel and feedstock for its hydrocracker unit. In late 2006, due to a gas shortage estimated at 42% below the plant's required volumes, it was forced to use its own high-value products, such as butane, propane and ultra-low-sulfur diesel, to fuel the refinery.

---

[1] Presentation of Tony Izzo, President/CEO of ENSTAR Natural Gas Company, Energy Supply in South Central Alaska (2006).

[2] State of Alaska Department of Natural Resources, 2007 Annual Report, p. 3-25 (July 2007).

It is expected that the Marathon/ConocoPhillips liquefaction facilities in Nikiski, which have been shipping LNG to Japan since 1969, will also cease operation in the next few years.

DOE predicts that around 2011, not only will there not be enough gas for heavy industrial use, but Cook Inlet gas production will no longer be able to supply electric power generation demand.[3] Beyond 2015, consumer gas utility demand is expected to outstrip local supply.[4]

The consequences of not securing the supply of ANS natural gas to the South Central region by 2015 could be severe. The curtailment of industrial consumption of natural gas in Nikiski for the production of urea, refining, and LNG export would result in significant job losses in the Kenai area. Further, power generation along the Railbelt will have to use more expensive fuel substitutes, which could mean not only significant increases in electricity generation costs but could also incur high switchover costs. Alaska, which has the largest undeveloped natural gas reserves in the United States, could become an importer of LNG.

2.1.1.4(b) Receipt Points

The principal receipt point for natural gas transported on the Pipeline will be Prudhoe Bay, at the outlet of the GCP. The Port Authority anticipates the discovery and development of new natural gas reserves in locations in Alaska outside of Prudhoe Bay, such as, for example, the Foothills area. Monetizing such natural gas reserves could necessitate the provision of additional receipt points along the Pipeline route that enable shippers to market such gas without the need to first transport it to Prudhoe Bay.

To the extent that gas producers and prospective shippers in areas such as the Foothills, or other areas, are ready to make gas available for commitment in the initial binding open season, the Port Authority will work with such producers and prospective shippers with the aim of modifying the Pipeline design to achieve a rational and cost-effective distribution of receipt points and accommodate the need of such shippers to have access to the Pipeline.

To the extent the need for such additional receipts points arises after the initial open season, the Port Authority will accept and evaluate requests for such receipt points during the periodic market assessments for expansion mandated by AGIA.

2.1.2 North Slope Gas Conditioning Plant (GCP)

For the purposes of this Application, it has been assumed that gas conditioning and treatment services at the GCP will be provided to the Project on a third-party basis by other entities. It is anticipated that the owners of the GCP will include companies with significant experience in the gas processing sector ("**GCP Participants**").

[3] Id. at 11.

[4] Id.

In order to achieve the most attractive commercial terms for the GCP, the Port Authority has deferred the negotiation of definitive commercial arrangements with prospective GCP Participants until the Project development phase.

The Port Authority is currently in discussions with a regional native corporation ("**Regional Corporation**") as a prospective GCP Participant. Based on industry experience, familiarity with Alaska and their financial successes over the past many years, the Port Authority believes that the Regional Corporation would be an appropriate entity to perform this function.

As the provision of gas treatment services is assumed to be provided to the Project on a third-party basis, this Application does not include a detailed technical description of the GCP in the Project scope. It has been assumed that the technical parameters of the GCP will be consistent with those developed for the Pipeline and the LNG Facilities.

It is assumed that the treatment will include dehydration to the equivalent of <0.1 parts per million ("**ppm**"), and removal of carbon dioxide and contaminants such as hydrogen sulfide and mercury. The gas composition and conditions required at the outlet of the GCP are provided below.

Table 4 Gas Composition and Conditions Required at the Outlet of the GCP

	Lean Gas Composition	Rich Gas Composition
Pressure	1150 psig	1150 psig
Temperature	40 °F	40 °F
Methane	91.26 %Mol	87.71 %Mol
Ethane	5.89 %Mol	7.21 %Mol
Propane	1.73 %Mol	3.65 %Mol
i-Butane	0.10 %Mol	0.31 %Mol
n-Butane	0.20 %Mol	0.41 %Mol
C5+	0.10 %Mol	0.10 %Mol
Nitrogen	0.71 %Mol	0.61 %Mol
H2S	0.00 %Mol	0.00 %Mol
H20	0.00 %Mol	0.00 %Mol
CO2	<100 ppm	<100 ppm
Mercury	0.00 %Mol	0.00 %Mol

It is assumed that any NGLs or other by-products of the gas treatment process will be owned and marketed by other entities, such as the ANS natural gas producers.

2.1.3 LNG Project

2.1.3.1 LNG Facilities in Valdez

The LNG Facilities will be located at Anderson Bay in the area of Valdez, pursuant to the authorization granted by the Federal Energy Regulatory Commission ("**FERC**") for such a facility, which is discussed in Section 2.2.4.1 below.

2.1.3.1(a) General

The proposed LNG plant will be a grassroots, completely self-sufficient facility for three LNG trains to produce a nominal 5 mmta of LNG from each train. For the purposes of this Application, the LNG Facilities design has been prepared on the basis of utilizing the ConocoPhillips Optimized Cascade^{SM} Liquefaction Process Technology. This technology is well proven with successful implementation at five LNG plants and nine LNG trains, including the facility in Kenai, Alaska, which has operated for more than 35 years without missing a single LNG shipment. The current process design for the LNG Facilities is based on a proven design template with all the proposed equipment and systems in successful operation over an extended period of time at other plants.

During the development phase of the project, the Port Authority would evaluate the potential use of alternative LNG technologies.

Feed gas will be transported from the ANS through the Pipeline. The feed gas will be free of moisture, acid gases such as hydrogen sulfide and carbon dioxide, and mercury and is expected to have the following specifications:

Composition (mole %):

Component	Lean	Rich
N2	0.7	0.6
Methane	91.2	87.7
Ethane	5.9	7.2
Propane	1.7	3.7
i-Butane	0.1	0.3
n-Butane	0.2	0.1
i-Pentane	0.1	0.1
CO2	<100 ppm	<100 ppm

Feed temperature:	15.5 °F
Pressure:	1,300 psia downstream of the flow control valve
Flow Rate:	approximately 2.7 bcfd to support three LNG trains

At the beginning of the operation of the LNG Facilities, the gas will arrive with moisture which will require drying. Therefore, a moisture removal unit will be installed to dry the wet gas arriving during the pipeline dry-out. This dry, carbon dioxide-free, and mercury-free gas is subsequently fed to the refrigeration system where it is liquefied as the LNG product.

There are three refrigeration services, propane, ethylene, and methane, which are optimally cascaded. Each of the three refrigeration systems uses two 50-percent capacity refrigerant compressors with common condensers, chillers, and accumulators. Each of the compressors is driven by a gas turbine.

Cryogenic distillation facilities are provided to remove sufficient propane and heavier hydrocarbons. This is accomplished by processing the feed gas at an optimum thermal condition during its cooling and condensing trip through the refrigeration system. The light ends are stripped from the feed and the recovered C3+ liquid hydrocarbons are fractionated into propane, butane, and light condensate. The propane and butane are stored in separate fully refrigerated storage tanks. The storage system includes product pumps for ship loading. The light condensate is stored in a tank and is pumped into barges.

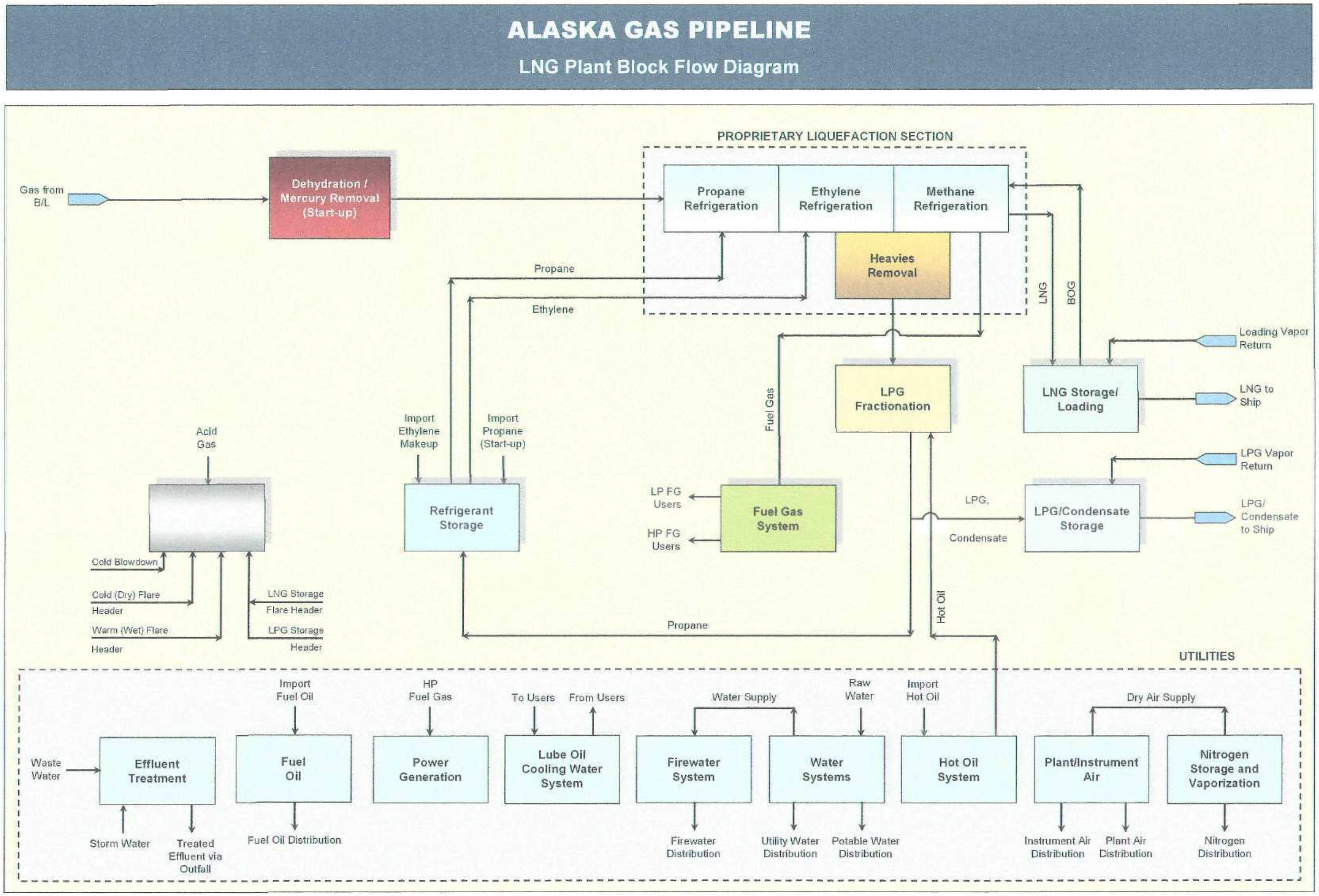
LNG storage is in two double-containment storage tanks. The storage system includes product pumps for ship loading. Boil-off gas compressors are provided for handling the vapors from the heat gain, displaced volume, and the flashing gas.

The facility uses air cooling, and it generates all its required electrical power. Potable water and firewater are stored on site in a large fresh water storage tank. Other required utilities, compressed air, nitrogen (for purging), wastewater treatment, and sanitary sewer treatment are also provided on site.

High-purity propane (for start-up only) and ethylene (for start-up and operation) are imported. After start-up, propane product from the LNG Facilities will be used as propane refrigerant make-up.

Figure 5 below shows a block flow diagram for the LNG Plant.

Figure 5 LNG Plant Block Flow Diagram



The LNG plant consists of the following units:

- Inlet Separation
- Dehydration
- Propane Refrigeration
- Ethylene Refrigeration
- Liquefaction and Methane Compression
- Heavies Removal, NGL Recovery and LPG Fractionation
- Flares
- Refrigerant Storage
- Miscellaneous Storage
- Fuel Gas System
- Propane, Butane and Condensate Storage and Loading
- LNG Storage and Loading
- Effluent Treatment
- Power Generation
- Cooling Water System
- Firewater System
- Hot Oil System
- Plant/Instrument Air
- Water Systems
- Nitrogen System
- Jetty and Construction Dock

The subsections below provide a detailed description of each of the LNG Facilities units.

2.1.3.1(b) Inlet Separation

Gas to be processed at the LNG Facilities will be transported through the Pipeline from the ANS. Inlet slug catcher, PIG receiver, and feed gas custody metering systems for the LNG Facilities are part of the Pipeline scope. Gas inside the LNG Facilities battery limit passes through a pressure control valve and a flow control valve, and then to the feed gas filter coalescer, where liquid droplets or solid particles greater than 1 ppm are removed.

2.1.3.1(c) Dehydration and Mercury Removal

During normal operation, the feed gas arriving via the Pipeline will be free of CO_2, moisture, and mercury. However, during the initial start-up, moisture collected from water in the pipeline needs to be removed in the molecular sieve dehydrators.

Adsorption Cycle

The molecular sieve unit consists of three dehydration beds, any two of which will be in the adsorption mode with the third bed in regeneration or on stand-by. Each bed contains molecular sieves. Feed gas enters two of the three molecular sieve dehydrators that are on the adsorption cycle. The water vapor is removed from the feed gas and is retained within the molecular sieve during the whole adsorption cycle. A down-flow path is used to avoid fluidizing the beds.

Regeneration Cycle

Dryers are regenerated by backflowing clean, dry effluent gas at an elevated temperature from the regeneration gas heater. The hot regeneration gas passes up through the molecular sieve bed where the adsorbed water is stripped off restoring the adsorption capacity of the sieves.

Cooling Cycle

During this cycle the heater is turned off and the cooled gas flows the same path as the regeneration gas.

After the heating cycle, the regeneration gas flow is switched back to the down-flow pattern. The regeneration and dryer switching is controlled via programmable controller and switching valves.

At this point, the feed gas is dry before being sent to the cryogenic section. Continuous samplings are provided to indicate moisture content on the DCS with high alarm.

Mercury guard bed is provided for the removal of mercury in the feed gas.

2.1.3.1(d) Propane Refrigeration

Propane refrigeration chills the feed gas prior to liquefaction, and condenses (is cascaded to) the ethylene and methane compressor discharges. Additionally, propane refrigeration is used to refrigerate propane and butane products, as well as their respective product storage tanks. Two 50-percent compressors are used in parallel, each driven by a gas turbine.

2.1.3.1(e) Ethylene Refrigeration

Ethylene refrigeration cools, condenses, and slightly sub-cools feed gas, and cools and condenses the methane compressor discharge. Two 50-percent compressors are used in parallel. Each of the compressors is driven by a gas turbine.

2.1.3.1(f) Liquefaction and Methane Compression

This unit comprises liquefaction and methane refrigeration compression. Each of the compressors is driven by a gas turbine.

2.1.3.1(g) Heavies Removal, NGL Recovery and LPG Fractionation

The chilled feed gas stream is separated into various components and undergoes further processing to obtain LNG, propane, butane and condensate.

2.1.3.1(h) Flares

The LNG Facilities will include process and marine flares to handle any overpressure in the plant, emergency depressurizing, blow down and drains.

2.1.3.1(i) Refrigerant Storage

Refrigerant storage is provided for periodic fill-up of the system during start-up, make-up to the refrigerant circuit as well as refrigerant storage during maintenance.

2.1.3.1(j) Fuel Oil Storage

A fuel oil storage drum is provided to operate the fire water pumps.

2.1.3.1(k) Fuel Gas System

The high-pressure fuel gas system supports main turbine refrigeration drivers, the turbine electric generators and low pressure fuel gas supply for the fired heaters and flares.

2.1.3.1(l) Propane, Butane and Condensate Storage and Loading

Double-integrity, atmospheric and refrigerated tanks capable of handling propane and butane are provided to store the products. The propane and butane are transferred to ships via loading arms. A third loading arm is provided to handle ship tank displaced gas, gas flashed from the propane/butane product, and gas vaporized from the heat gain. The gas from the propane tank and from the ship loading system are compressed by the propane boil-off gas compressor and returned to the process unit for condensation.

Condensate product is stored in a floating roof tank and is pumped to barges through loading arms.

2.1.3.1(m) LNG Storage and Loading

Two double-wall, full-containment LNG storage tanks, complete with level gauging, level transmitters, relief valves, vents, temperature elements, and other basic instrumentation are provided for three LNG trains. Four submerged loading pumps are furnished for each tank with a combined capacity of 10,000 cubic meters per hour unloading rate from both tanks.

The LNG product is pumped through a loading line to the loading dock. This piping is maintained full of liquid and at the same temperature as the tank liquid through a recirculation line during the holding mode. Any vaporized gas is fed to the boil-off gas compressors.

The LNG is transferred to ships via two 6-inch diameter loading arms. A third 16-inch loading arm is provided to handle ship tank displaced gas, gas flashed from the LNG product, and gas vaporized from the heat gain. This gas is returned to the LNG tanks via a separate vapor return line. An LNG drain sump is provided at the loading dock to drain liquids from the loading arms.

The loading arms are of a swivel joint design suitable for cryogenic service, and are fully balanced and self-supporting. The swivel joints are equipped with connections for nitrogen purging. Quick-connect and disconnect couplers are also provided. Each loading arm is equipped with a remote hand-operated valve, vent valve, and high-pressure alarm.

The vapors from the LNG tanks and from the ship loading system are compressed by the boil-off gas compressors and returned to the open cycle methane LNG plant refrigerant system. Excess gas that may be produced during the ship loading is sent to the LNG marine flare. The boil-off gas compressors are electric motor driven centrifugal compressors designed for the cryogenic service.

The second jetty with two additional 16-inch diameter loading arms and one additional 16-inch vapor return loading arm are provided for three LNG trains operating; both jetties will operate concurrently.

2.1.3.1(n) Effluent Treatment

The effluent treatment unit provides collection of storm water and oily water from the plant and is treated to meet all applicable local, state, and federal environmental regulations and guidelines before proper disposal. Sanitary sewage and the wastewater from administration building, shop, control room, and the warehouse are collected via underground lines and treated to meet applicable regulations.

2.1.3.1(o) Power Generation/Distribution

The electrical system, located within the LNG Facilities, is energized by gas turbine generators with distribution substations and MCC buildings located in each train.

A stand-by generator system serves to black start the gas turbine generator system, and when the gas turbine generator system is shut down, it serves as the standby generator system to provide electrical power to essential plant loads and essential loads in the control building.

UPS systems are provided to supply the DCS, ESD, and other equipment requiring continuous power. These additional individual UPS systems are located in the MCC buildings, the main control building, and compressor control MCC building in each train.

2.1.3.1(p) Cooling Water/Glycol System

The lube oil cooling water/glycol system provides the cooling duty for the turbine compressor lube oil coolers. Nitrogen pad gas is provided to avoid vacuum conditions. The cooling water/glycol is circulated through the compressor lube oil coolers, cooling the lube oil. The lube oil cooling water coolers then cool the water by air exchange.

2.1.3.1(q) Firewater System

The LNG Facilities have been provided with a self-sufficient fire protection system to control or extinguish a fire within the facility. The design of the fire protection system is based on the single fire philosophy. The primary fire protection system is the firewater system, which is charged with well water.

Fresh water from wells is pumped to and stored in the firewater tank. Firewater is pumped from the firewater tank through a ring-main distribution system to hydrants, monitors, and hose stations.

Two electric, motor-driven jockey pumps are provided to pressurize the firewater ring. One pump runs continuously to maintain system pressure. On low pressure, the stand-by jockey pump will auto-start. The main firewater pumps operate on the fuel oil and one pump is motor-driven. Firewater monitors and hose stations are tested regularly to assure that the firewater system is fully functional and there are no leaks in the distribution system.

An extensive underground distribution system is connected to above-ground hydrants, monitors, and hose stations to provide fire protection coverage to the process area, storage area, and the jetty.

A combination dry chemical/foam fire truck is used.

2.1.3.1(r) Hot-Oil System

A hot-oil system is a closed-loop circulation system provided to service the process heating requirements. Therminol 59, or an equivalent heating oil, is selected for this service due to its properties in the temperature range – specifically, its pumpability. There is a single system for the entire LNG plant.

The hot-oil surge drum provides full de-inventory of the plant hot oil system piping and other related equipment if required to correct an equipment problem or during maintenance. A sump is provided to permit draining of the hot oil system piping and equipment, complete with a sump pump. Hot-oil pumps are provided to pump the hot oil from the surge drum through the hot-oil heaters to the hot-oil users. Only one of the pumps is used at a time, providing a complete spare.

Two direct-fired heaters are provided for the heating; fuel to the heater is provided from the low pressure fuel system.

The hot-oil system provides the heating service to the reboilers in the fractionation unit and building heaters.

2.1.3.1(s) Plant/Instrument Air

Plant utility air, instrument air, and feed air to the nitrogen generation system is supplied as bleed air from the air compressor of the gas turbines driving the electric power generators. Plant air is designed for three LNG trains.

The air from the air receivers is available for plant utility use or is subsequently dried through the air dryer packages and then distributed from the plant/instrument air receivers.

A motor-driven auxiliary air compressor, complete with discharge coolers and controls, is provided as a partial back-up to the bleed air system from the gas turbines. This system will supply all necessary instrument air required for plant start-up, including nitrogen generation system requirements.

2.1.3.1(t) Water System

The water system provides supply and distribution to meet the need for fresh water, potable water and service water for the LNG Facilities operation.

2.1.3.1(u) Nitrogen

Air separation units are provided for producing nitrogen at the site which is used for blanket gas for storage tanks, purge gas for the cold boxes, loading arm swivel joint purges, compressor gas seals and buffer, and as purge gas required for repair and maintenance services and for other general purposes.

2.1.3.1(v) Jetty and Construction Dock

The Valdez site is an ideal harbor for large ocean-going vessels due to the deep water surrounding the site. The lean gas case design is based on the first jetty being installed with Train 1 and the second jetty coming in line with Train 3 (for the rich gas case, the second jetty must be installed with Train 2 due to increase in propane and butane shipments). Jetty No.1 is approximately 270 feet long, and Jetty No. 2 is 500 feet long. The design is based on of one docked ship per jetty with concurrent loading. LNG will be loaded from either jetty. LPG and light condensate will only be loaded from Jetty No. 1.

The construction dock design consists of a berthing face length of 500 feet and a depth of water at the face to accept vessels with a maximum draft of 23 feet. The construction dock will provide three separate locations where a crawler crane can be placed to unload barges. An access approachway will be provided for each crane placement location. The construction dock will also provide access to the construction road to the plant.

2.1.3.2 Marine Transportation for LNG and NGL

2.1.3.2(a) LNG Tanker Transportation

The Project will not own LNG tankers. LNG marine transportation services will be obtained from third parties, under long term time charter arrangements typical in the LNG industry. The providers of marine transportation services will be selected under a competitive tender process.

The Port Authority has developed a relationship with the MOL Companies. MOL is a global leader in marine transportation and has the largest tanker fleet in the world, including crude carriers, product carriers, LNG carriers, LPG carriers and methanol carriers. MOL is a leader in LNG transportation for LNG projects worldwide. MOL and its group of companies own and/or participate in 80 LNG vessels (including 21 vessels under construction), which represents approximately a quarter of the world's existing (or under construction) LNG vessels. A detailed description of MOL's LNG fleet is provided and its experience in LNG projects is provided in Appendices K.

Pursuant to a Teaming Agreement between the Port Authority and the MOL Companies (attached as Appendix L), the Port Authority and the MOL Companies have agreed to work together to develop the marine transportation elements of the Project, including the development of a plan for procurement and implementation of LNG transportation services in structure that is most suitable to the Project.

Pursuant to the Teaming Agreement with the Port Authority, the MOL Companies have provided a cost estimate for marine transportation services based on several options for new-building LNG vessels. The data in the cost estimate provided to the Port Authority contains proprietary information that is confidential, and such information has been excluded from the public portion of this Application. The confidential cost estimate data is attached separately in Appendix K.

In addition to its relationship with the MOL companies, the Port Authority has also been in discussions with a major Japanese industrial conglomerate, whose business activities include the trading and marketing of LNG and the provision of LNG tanker services. This company has provided to the Port Authority an additional confidential cost estimate for LNG marine transportation for the Project.

The number of LNG tankers required to transport the LNG volumes is primarily a function of: (a) tanker size; and (b) distance to the destination market. The precise fleet configuration for the Project will be determined once the actual sales volumes of LNG to each market in Japan, Korea and/or Taiwan has been finalized, and binding bids under a competitive tender for the provision of marine transportation services have been obtained by the Project. At this time, it is anticipated that the LNG tankers for the Project could range between 147,000 cubic meters ("**m^3**") and 177,000 m^3 class. Vessels in this size range are optimal for the Project in terms of cost and access to East Asian receiving terminals.

Depending on the allocation of offtake LNG volume and the size of vessels selected by the Project, it is anticipated that between 12 and 18 newbuilding vessels would be required to transport the volume of LNG produced. Detailed description and technical characteristics of the different classes of vessels which are currently being evaluated as options for the Project are provided in the confidential Appendix K.

A description of the process of procuring LNG marine transportation services for the Project and the anticipated commercial arrangements for the LNG tanker component of the Project is provided in Section 2.2.3.14(f).

2.1.3.2(b) LPG Tanker Transportation

LPG marine transportation services will similarly be obtained from third parties pursuant to a competitive tender process. LPG tankers are available for chartering on a short term basis, e.g., one year, or on longer term basis of ten or more years.

Pursuant to the Teaming Agreement between the Port Authority and the MOL Companies, the Port Authority and the MOL Companies have agreed to also work together to develop the LPG tanker transportation framework for the Project. MOL has 45 years of experience in the LPG tanker business and was the first owner of a fully refrigerated LPG carrier in the world. MOL is an owner and operator of five very large gas carriers ("**VLGCs**"), which are LPG tankers with a capacity in excess of 70,000 m^3, one mid-size ammonia carrier and one pressurized LPG carrier. MOL is the operator of an additional three VLGCs and has a further ten LPG and ammonia carriers under its management. A description of MOL's LPG fleet and expertise in LPG tanker services is provided in Appendix M.

2.1.4 Gas Processing and NGL Markets

The following aspects of the Project will involve gas processing and marketing of NGLs: (a) NGL removal the GCP at Prudhoe Bay; (b) potential future NGL extraction facilities along the Pipeline route; and (c) the integrated liquefaction and fractionation LNG Facilities in Valdez.

2.1.4.1 NGL Extraction at the GCP

It is anticipated that the GCP will be capable of extracting heavier NGLs (pentanes+), which can be blended into the TAPS stream. As described in Section 2.1.2 above, it is anticipated that the GCP will be owned and operated by third parties, and, therefore, this Application does not include a proposal for removal and marketing NGLs at the GCP in Prudhoe Bay.

2.1.4.2 Potential Future NGL Extraction in-State

It is envisioned that pipeline tees will be installed and capped at various locations in Alaska, in order to facilitate the possible future offtake of gas for sale and/or further processing for the extraction of NGLs or other products. However, the quantity of such offtake, the nature of processing, or the potential marketing of gas, NGLs or other products has not been considered further at this time.

2.1.4.3 LPG Extraction at the LNG Facilities in Valdez

The lighter NGL fractions, ethane, propane and butane, which cannot be safely blended into the TAPS stream and will not be extracted at the GCP, will be transported through the Pipeline to Valdez for processing at the LNG Facilities. At this time, the Port Authority does not anticipate the near term development of an ethane-consuming petrochemical industry in South-central Alaska and, therefore, no assumption has been made for ethane extraction and marketing in the initial Project design. The Port Authority, however, is committed to providing maximum opportunity for Alaska to benefit from the monetization of ANS natural gas by making available gas and NGLs to local consumers and industries and thus spurring the growth of new industries, including ethane-based petrochemical facilities or other similar consumers of NGLs in the State. The Port Authority will periodically assess the market interest in adding ethane-extraction capability to the Project to serve the development of such new value-added industries.

Until such ethane processing capability is developed in the future, the ethane fraction in the ANS gas will be included in the LNG produced at the LNG Facilities. It should be noted that East Asian LNG buyers are accustomed to receiving LNG with a high heating value and that, as discussed in Section 2.10.1.1 below, the forecast prices for LNG in the targeted markets are highly attractive and, therefore, the ethane fraction in the natural gas stream will obtain a high sales value.

Alternatively, in the event that a Canadian pipeline is developed in the future to transport ANS gas to markets in Canada and the U.S., the Port Authority is committed to working with the sponsor(s) of such project and with shippers of natural gas to determine the optimal location of gas processing and NGL extraction facilities that would provide the highest value for Alaskan NGLs by maximizing their marketing options. In one such scenario, it is anticipated that a gas processing and NGL extraction facility could be located at Delta Junction to enable the redirection of NGLs to the best market available at each point in time via either (a) the Valdez terminal for sea-borne shipping worldwide, or (b) the Canadian pipeline to markets in Canada or the U.S. Midwest.

Extraction of NGLs in Alaska would allow for the opportunity of value-added industries in Alaska. The Agrium plant in Nikiski uses natural gas to produce fertilizer and generates over 100 jobs in that area. Value-added processing in Alaska would further maximize the benefit to Alaska through additional long term employment and infrastructure.

Anticipated commercial arrangements for the LPG extraction and marketing functions are described in Section 2.2.3.15 below. For a description of the targeted markets for propane and butane, please refer to Section 2.10.1.1(f).

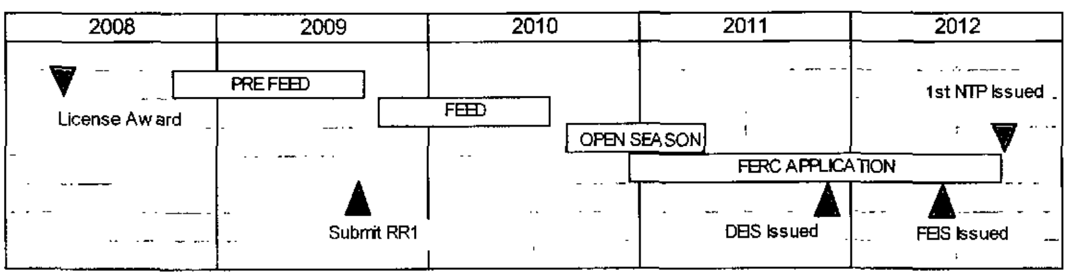
2.2 Development Plan

This section provides the development plan for the project ("**Development Plan**"), which as required under the RFA has been prepared to cover "all steps toward obtaining required Certificates of Public Convenience and Necessity and other approval required prior to the start of execution." Listed below are the issues addressed in the Development Plan and the sections in this Application that cover them:

- Front-End Engineering Design Plan (see Section 2.2.1);
- Stakeholder Issues Management Plan (see Section 2.2.2);
- Commercial Plan (see Section 2.2.3);
- Regulatory Plan (see Section 2.2.4);
- Local Project Headquarters Plan (see Section 2.2.5);
- Environmental Management Plan (Appendix QQ);
- Schedule for Development Phase (see Section 2.6.1); and
- Cost Estimate for Development Phase (see Section 2.5.1).

For the purposes of this Application it has been assumed that the development phase will run for 54 months, from the issuance of the License (expected in April 2008) through the issuance of the first notice to proceed ("**NTP**") under the Project's EPC contracts (expected in September 2012). The Project development phase has been sub-divided into four separate time related activities (see Figure 6 below): (1) Pre-FEED; (2) FEED; (3) Open Season; and (4) FERC application process.

Figure 6 Development Phase Schedule Summary



The purpose and activities within each of these four time-related activities are addressed in sections below. To facilitate their successful conclusion, the activities will be managed by a Project Director who will give direction to the Program Director appointed by the contractor providing project management and/or engineering, procurement and construction management ("**EPCM**") services for the Project. For the purposes of this Application, it has been assumed that Bechtel will perform this role, and the Development Plan has been prepared accordingly. The Bechtel project management team ("**PMT**") would coordinate the activities horizontally across the Project team areas (e.g., LNG Facilities and Pipeline) and vertically between project disciplines (engineering, environmental, permitting, procurement, labor relations, lands, etc).

During the development phase of the project the concept of front end loading ("**FEL**") is key to delivering the most optimized, value adding definition for the project to take forward to the execution and operational phases. Opportunities for value capture and value maximization are greatest in the early stages of the development phase and the Port Authority intends to work closely with our prospective Project partners and stakeholders to achieve this. The FEL activities will focus the project to narrow the uncertainty range, reduce risk, provide technically deliverable solution and understand the critical risk factors and issues.

Activities during the development phase which will facilitate a high level of FEL for the Project include:

- early framing workshops with the Project Director, the Bechtel PMT and key stakeholders to fully define and communicate the project boundaries, objectives and critical success factors;
- within six weeks of License award establish a Project-specific value assurance plan, which will define the key assurance activities to be undertaken during the development phase of the project. This will include as a minimum:
  - Project scope and objectives,
  - stage deliverables through the development phase,
  - resource plan to achieve deliverables,
  - risk and opportunity management plan,
  - Project-specific health, safety, security and environment ("**HSSE**") management plan to cover all development phase activities,
  - quality assurance/quality control plan to cover all development phase activities with particular emphasis on the FEED design activities,
  - contracting strategy plan,
  - establishing technical, economic and commercial basis and assumptions;
- assessing usefulness and required updates for existing YPC permits;
- early scoping meetings with stakeholders; and
- team alignment meetings with key Project partners.

Given the technical complexity of the Project, it is anticipated that a significant number of independent assessments will be undertaken during the development phase of the Project. The reviews will be multi-discipline and include not only engineering specialists but also other functions, e.g., project management, construction management, operations, HSSE.

A "Design Change Management" procedure will be developed for the Project. As it is anticipated that Bechtel will be responsible for the execution of the pre-FEED and FEED work during the development phase, such Design Change Management will be based on Bechtel's internal procedure. During the early stages of the development phase, the Basis of Design ("**BoD**") document will be agreed with all relevant stakeholders. This document will constitute the primary Project document that would be subject to change control under the Design Change Management procedures. At the end of the development phase, the BoD and all design documents produced will be 'frozen' and any subsequent changes would be subject to the formal execution phase change control procedure.

Bechtel Organization for the Development Phase

It is Bechtel's intention to establish a permanent local Project Headquarters within the State of Alaska. Bechtel's PMT will be located in Anchorage, Fairbanks, Valdez and Houston.

During the development phase, the Bechtel PMT, under the leadership of the Port Authority (and its partners) as Owner, will be responsible for the following activities:

- acting as the focal point for governmental agencies, authorities, non-governmental organizations ("**NGOs**") and other public bodies;
- coordination and liaison with the ANS gas producers;
- coordination and liaison with the Alyeska Pipeline project team and other major interface areas;
- supervision and coordination of day-to-day performance of the overall Project and between the various Project teams;
- development of local labor relations and agreements;
- forward manpower planning / re-sourcing and the associated training to meet project needs;
- management and administration of the contract and project subcontracts, purchase orders and leases;
- preparation of the general planning for the performance of the Project services, plus the corresponding budgets and their execution;
- detailed planning, hiring of specialized and local services, subcontracting and procurement;
- day-to-day supervision of cost control, accounting, and all commercial activities with respect to the Project;
- day-to-day compliance with the approved project procedures, especially those pertaining to health, safety, environmental compliance, and community/public relations; and
- presentation with, and at the request of, the Project Director of the Owner of technical, production, cost, economic and financial progress reports.

During 2008 and 2009, the PMT along with the project teams for the LNG Facilities and the Pipeline will concentrate on Project definition and development of engineering and resource-related information for the initial applications to State and Federal regulatory and land management agencies. Once the assumed FERC application has been filed in 2010, the emphasis will change from planning and definition in the two FEED phases to detailed design development and development of site-specific design and design packages to support procurement activities and prepare for mobilization.

During this period, the PMT will also be providing ongoing support to the permitting process, responding to questions and requests for supplemental information, and incorporating feedback from the environmental review and approval process into the

Project's design basis. Throughout this period, the Project must still be managed on numerous fronts to ensure that ongoing design development progresses are at a pace consistent with project development milestones and reflects guidance from the various governmental agencies charged with responsibility for Project review and approval. Hence, although the staffing levels with each of the two project areas may decline during 2010 and 2011, the staffing within the PMT will remain approximately constant as the Project moves forward.

The pre-FEED work includes the following:

- preparation of work plans and access requests for initial studies to support design definition and regulatory filings;
- contracting for survey work (geotechnical, environmental baseline studies, etc.);
- preparation of a process design basis for the FEED (all required studies – drivers, layout, etc.);
- preparation of a FEED design basis (design philosophies, standards, deliverables, etc.);
- initial recons and routing studies;
- initial plans for temporary facilities and infrastructure development; and
- selection of a preliminary pipeline route alignment.

The FEED work includes the following:

- confirmation of the LNG process design;
- confirmation of pipeline route alignment and location of ancillary facilities;
- location of compressor stations;
- location of construction camps;
- development of process flow diagrams ("**PFD**"), piping and instrument diagrams ("**P&ID**"), and equipment process data sheets;
- procurement bids for all equipment, bulks and subcontracts;
- preparation of design work to support regulatory filing;
- plot layout optimization;
- preparation of an EPC schedule;
- development of preliminary construction plans;
- preparation of a firm lump sum, turnkey price for execution phase of the LNG Facilities; and
- preparation of a +/- 10% cost estimate for the execution phase of the pipeline system under an EPCM contract strategy.

The Post FEED work includes the following:

- support to Owner in gaining FERC certification and rights-of-way;
- support to Owner for Project financing activities;
- acquisition of all other permits to support start of construction;
- potential early award of a few long lead items (LNG tanks, compressors, cold boxes);
- contracts ready to award for ground breaking site preparation activities;
- finalizing construction camp arrangements;
- arrangements for rental equipment; and
- mobilization planning.

Further details on the activities and execution philosophies undertaken during these phases are presented in Section 2.2.1 below.

It should be noted that certain tasks relating to detail engineering and initial procurement activities for the long lead items and subcontracts will be carried out during the same timeframe. However, such items are excluded from the development phase definition, and the resources and costs are within the EPC estimate rather than the development phase estimate.

Organization

The Bechtel PMT will assign a senior corporate sponsor for the Project, of a level of seniority commensurate with the scale and importance of the project. He will be well positioned to provide the corporate resources, leadership and oversight required to ensure that the Project is a success. The primary focus of the corporate sponsor for the Project will be to:

- ensure the timely assignment of highly qualified personnel to meet Project requirements and support the continuity of those personnel throughout the Project;
- understand the Owner's needs and communicate those needs to other members of the senior management and project execution team;
- champion the transmission and application of lessons learned from other successful projects;
- ensure consistency of systems and procedures across all aspects of the Project; and
- facilitate communications with the Owner's organization by providing a parallel communication channel that will supplement the normal channels established through the Project team.

The Bechtel PMT program manager will report to the Owner's senior responsible representative, as well as to the PMT's corporate sponsor within Bechtel's organization. The program manager will be responsible for the quality and timeliness of all deliverables to the Owner and ultimately for the execution of the EPC activities for the Project.

Major functional reports to the Bechtel program manager and the roles and responsibilities of these personnel during the FEED are listed below.

Segment Project Managers

The PMT will assign separate project managers for: (a) the LNG Facilities; and (b) Pipeline and compression work. They will manage all aspects of their respective scopes of work and serve as primary contact for the Owner's execution management.

Engineering Managers

As indicated in the organization chart, the PMT's plans to utilize two engineering managers: one for the LNG plant, and one for the pipeline and compression scope, each reporting to his respective project manager. However, there will be interfaces between these managers at the physical tie-ins between pipeline termination and plants, as well as in the project codes and standards, control/communications systems and standardization and synergies of various systems within their individual scopes of work.

Procurement Manager

The PMT's procurement manager will be responsible for purchasing, expediting, vendor surveillance and traffic functions through the shipment of project materials. It is expected that a single procurement manager with his supporting staff can handle all of the FEED duties.

Logistics Manager

One of the Project's greatest challenges is expected to be transportation of project materials, construction equipment (both transporting the PMT's and monitoring that of subcontractors' equipment spreads), and supplies into Alaskan locations. Accordingly, the PMT will assign a logistics manager to work with the procurement and construction managers to develop, during the FEED, a Project logistics plan for movement of all Project assets. This plan will be the basis for the freight and local transportation estimates, developed during the FEED.

Construction Managers

Similarly to the engineering managers, the PMT plans to utilize two construction managers: (a) one for the LNG Facilities; and (b) the other for the Pipeline and compression scope, each reporting to the respective project manager. These managers will work closely with the engineering managers for their respective scopes of work, the logistics manager, and with each other to ensure efficient execution. Interface management will be carried out within these two groups.

Contracts Manager

The contracts manager is responsible for all contract formation and administration activities related to the Project, both with the Owner and with subcontractors.

Estimating Manager

The estimating manager will work with each project team to define the project, develop the estimating criteria and produce the EPC estimate.

Business Manager

The business manager will be responsible for scheduling, cost control, accounting, and management reporting during the FEED.

Environmental, Health and Safety ("ES&H") Manager

The ES&H manager is responsible for developing the ES&H management plan and ensuring that the plan is properly executed and fully aligned with the owner's HSSE objectives, policies and procedures. He will also be responsible for project environmental issues.

Quality Assurance Manager

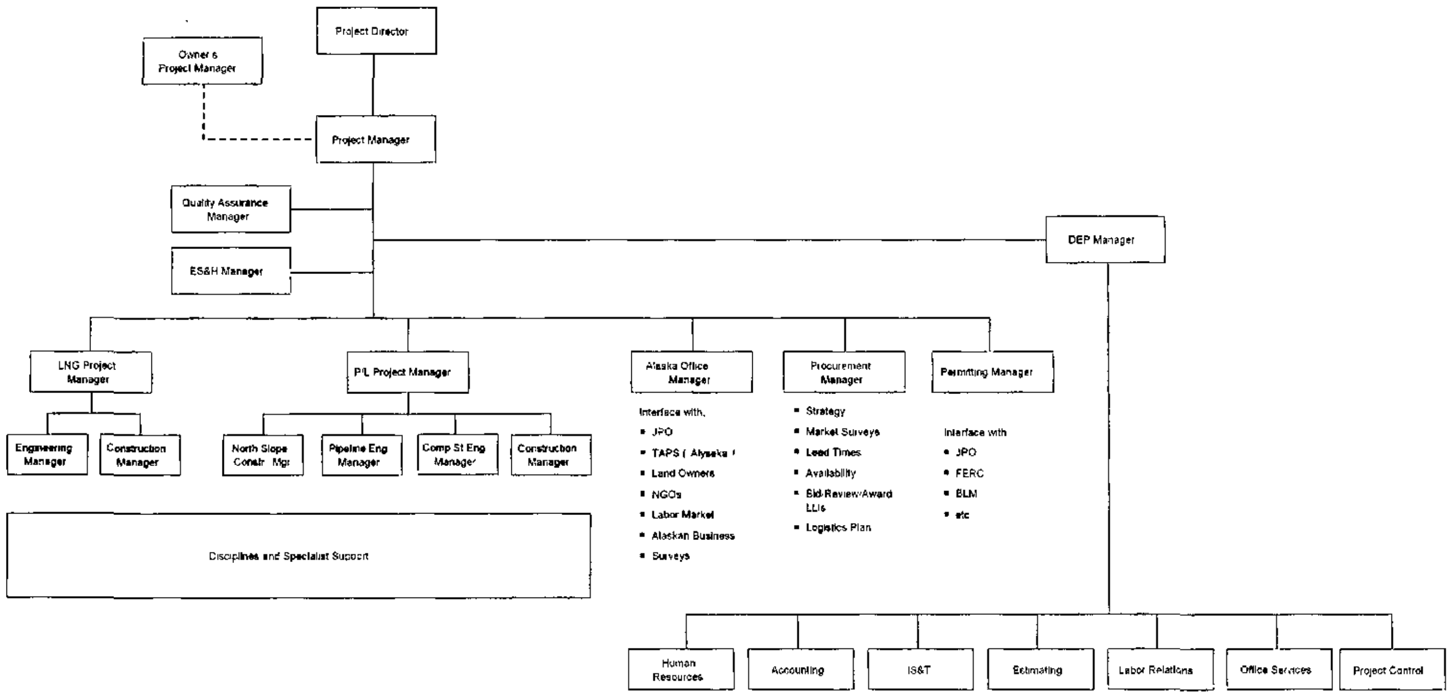
The Project quality assurance manager will be responsible for establishing the project quality management system, and for auditing its effective implementation during the FEED.

Owner's Project Management Team

The owners' PMT will be resourced to support the Pipeline and LNG Facilities FEED work.

Figure 7 shows the Bechtel organization chart for the development phase.

Figure 7 Development Phase Bechtel Organization Chart



2.2.1 Front End Engineering Design Plan

2.2.1.1 Objective

This section describes the pre-FEED and FEED work to be conducted during the development phase of the Project for both the Pipeline and the LNG Facilities. It explains work that is anticipated to be performed by Bechtel with input from the Port Authority and its partners in the role of Owner. The objective of this phase is to provide a firm scope and basis of design, all design documents and drawings to support the FERC application and resource reports, and a detailed execution cost estimate for the LNG Facilities and Pipeline to support the Project's financing plans and open season negotiations.

2.2.1.2 Pipeline Front End Engineering

2.2.1.2(a) Development Phase Objectives for the Pipeline

The objectives for the development phase are:

- To develop the engineering definition and pipeline route in sufficient detail to support:
  - the Resource Reports #1 to #12 for submission to FERC;
  - minimization of the environmental impact and development of preliminary mitigation solutions and plans;
  - input to the environmental impact statement ("**EIS**") and responses to issues raised during the draft EIS ("**DEIS**");
  - the FERC application;
  - development of the design basis for the Pipeline for submission to the joint pipeline office ("**JPO**"); and
  - the initial construction permits and NTPs. It is envisioned that the first NTPs will address: (a) Pipeline and access road ROW clearing and grading; (b) the set-up of the construction camps; and (c) use of borrow pits.
- To determine the segmentation of the Pipeline and compressor construction process. This will be developed following meetings with the JPO; however, it is anticipated that several NTPs will be needed to address all sections and all phases of the work. As a point of reference, 465 federal and 403 state NTPs were issued for the Alyeska pipeline.
- To identify and mitigate the risks that impact the permitting and NTP/FERC application process and those which may have an effect on cost and schedule;
- To provide the Owner with the data to construct a +/-10 percent estimate and associated schedule together with a quantified risk analysis to support the open season process and Project financing activities;
- Prepare contract packages and purchase orders so that material, equipment and contract awards can be made immediately following NTP.

To achieve these goals, it is planned that the engineering of the Pipeline and compressor stations will be almost complete at the end of the development phase. The only outstanding issues will be those related to the inclusion of vendor-specific data and any design amendments imposed by the permitting authorities prior to issuing the various NTPs.

2.2.1.2(b) Development Phase Schedule Impacts on the Pipeline

The proposed schedule assumes that work starts in the second quarter of 2008, immediately after the issue of the License, but too late to have a fully productive 2008 survey season. On this basis, and assuming 18 months for the EIS (12 months for draft and six months for final), the first NTP from the Bureau of Land Management ("**BLM**") and Alaska DNR will be issued in October 2012. Preparatory work and planning will commence following the award of the License to ensure fully productive 2009 and 2010 survey seasons, as the results will feed directly into the pre-FEED and regulatory submission process.

The development phase schedule has a number of key milestones, including:

- submission of resource report #1 (RR1) by month 17 (September 2009); and
- completion of the draft Environmental Reports (RR 2-13) and filing of the FERC application by November 2010.

The key to this schedule is maximizing the use of the existing YPC ROW and other available data required for FERC filing, such as:

- aerial photographs, although older than 12 months, are still largely valid since there has been very little development activity to render the photographs obsolete;
- 1:6000 YPC route maps exist;
- the YPC ROW center line is known, although some rerouting is anticipated;
- soil and geotechnical data at certain locations is known;
- much is know about the location and type of environmental constraints and mitigation measures address these constraints will have been developed;
- information exists on the need for some of the temporary access roads and work pads; and
- the location and extent of previously used borrow pits is known.

2.2.1.2(c) Execution Philosophy Pre-RR#1 Submission–Pipeline

Although the requirements to support FERC and other agencies' NTP processes are similar, the sequencing and timing of the input requirements are not. FERC requires a high level of definition early on in the process. For example, detailed routing, land take, and construction procedures must be defined for the first of the various resource reports. Hence, the design effort needs to be focused and planned primarily around the FERC process, while ensuring any additional requirements for the other NTPs are included.

The first and most critical deliverable that requires considerable technical data to be obtained and developed is the submission of the first resource report, ("**RR#1**"). In order to meet the scheduled date, the following major deliverables within three broad categories must be rapidly determined:

1. Pipeline system characteristics:

- diameter, wall thickness, grade, throughput;
- Pipeline route alignment
- number and location of all above-ground installations ("**AGIs**");
- number and location of all compressor stations, including future expansion requirements;
- SCADA definition;
- cathodic protection ("**CP**") and AC mitigation definition; and
- leak detection system

2. Construction procedures and engineering solutions in special areas:

- permafrost;
- intermittent permafrost;
- river crossings;
- road crossings;
- crossing of the Alyeska pipeline;
- pinch points where the Pipeline ROW interacts with the existing Alyeska pipeline;
- boring/tunneling;
- mountainous terrain;
- wetlands; and
- seismic faults.

3. The pipeline route and all land requirements:

- permanent ROW;
- permanent access roads, including turnarounds;
- temporary ROW and work spaces:
    - camps, fabrication and maintenance areas;
    - access roads, including turnarounds;
    - gravel pits; and
    - stock yards.

In order to meet these deliverables in time for the RR#1 submission, specific strategies need to be employed, as explained below. However, as the initial submission of RR#1 will take place prior to the start of FEED, and before the end of the summer 2009 first survey season, it is expected that the RR#1 report will need to be refined as further survey data is obtained and studied.

2.2.1.2(d) Pipeline System Definition

The Pipeline definition will be based on that developed during earlier studies for the Project and verified during the preparation of this Application. However, to arrive at an optimum solution, a number of verification studies will need to be conducted. These will include:

- verifying the use of X80 in terms of weldability, pre-heat requirements, fracture toughness and availability;
- compressor selection with respect to size, sparing, expansion, delivery, synergy with the LNG Facilities and cost;
- confirmation of the compressor sites in terms of topography, geology and access;
- the design flow rate and gas composition;
- use of microwave versus fiber-optic-cable-based SCADA systems;
- Pipeline coating systems, especially in the areas of poor backfill;
- above-ground (bridge) versus below-ground crossings;
- crossing of seismic faults;
- crossing of the major rivers;
- Pipeline route and location with respect to the existing Alyeska pipeline;
- crossing of mountainous terrain;
- permafrost design;
- frost heave study/design;
- thaw settlement study/design;
- workpad construction design;
- road construction design and upgrades;
- Project health, safety and environmental ("**HS&E**") development;
- logistic plans and trafficking requirements;
- socioeconomic impact studies and develop plans for employment; and
- resource HS&E training/craft skill training.

As part of this early work, specialist/optimization studies will focus on:

- mainline block valve spacing;
- block valve operations—remote vs. manual;

- strength testing—hydro vs. pneumatic testing and subsequent test plan:
- line-pipe joints lengths, i.e. 60 feet vs. 40 feet vs. double jointing; and
- the impacts of a cold gas pipeline in the non-permafrost regions.

2.2.1.2(e) Construction Procedures

In order to establish the total land requirements for the project, both permanent and temporary, it is important to understand what is required in order to construct the engineered solution. Under normal circumstances, this is a relatively simply task; for this Project, however, the variations in terrain, ground conditions and extreme weather conditions mean that the use of conventional pipeline installation procedures and planning norms must be augmented to accommodate the variants. Hence, specific construction methods/procedures will be developed for the critical areas, which will be identified from the topographic and geotechnical/geophysical surveys being conducted during the summer of 2009 and from the existing YPC data and public domain information. The various construction methods and procedures will be developed by the construction and engineering teams cooperating closely with the various environmental and permitting agencies and receiving guidance from them.

The key aspects will include:

- construction in the continuous and discontinuous permafrost so that the integrity of the existing ground is not violated (the procedures must also address the management of the pipeline in and around areas subject to frost heave);
- the optimized weather window for specific activities;
- construction in the vicinity of TAPS, especially those sections that are buried;
- location and construction of the various construction camps to ensure that land usage is optimized and that emissions are controlled and spillages eliminated;
- the location and management of gravel pits and other natural resources; and
- the organization and control of movements along the ROW and logistical issues associated with transports line-pipe, materials, equipment and labor along the 800-mile pipeline route.

2.2.1.2(f) Pipeline Route and Land Requirements

In principle, the Pipeline will follow the route of the existing TAPS pipeline, but at an offset distance of not less than 200 feet. In sections where an offset less than 200 feet is necessary, even while utilizing the existing ROW, specialist studies and surveys will be undertaken to establish the most favorable way to route the new pipeline.

During the summer of 2009 and 2010, various pipeline surveys will be conducted as listed below to either supplement existing information or as a new basis:

- satellite imagery to 2m pixel definition which will be used to establish the basis for the aerial surveys;

- aerial photography supported by Lidar to establish a 3D terrain model, route maps, ground contours, and land use. The resulting maps will enable the development of 1:6000 (1 inch to 500 feet) route maps;
- aerial-based geophysical surveys (electromagnetic/ground penetration radar) to establish soil types and categories to a depth of 10m and more;
- detailed topographic survey plus staking of the ROW and temporary requirements to develop local 1:600/300 construction drawings for areas of particular interest;
- local topographic and geotechnical surveys at each of the compressor stations and major AGIs;
- the location of each of the block valve sites will be checked for access, terrain and other features that may impact its construction and/or operation (if the location is found to be inappropriate alternatives will be sorted, with detailed surveying of these locations likely not taking place until 2010);
- local topographic and geotechnical surveys at major river crossing and points of major interest/concern as identified by the aerial-based geophysical surveys; and
- local topographic and geotechnical surveys of borrow pits to establish quantities, availability and impacts.

2.2.1.2(g) Execution Philosophy FERC RR#1 to FERC Application–Pipeline

Following the submission of the RR#1 to FERC, the Project team has three primary objectives:

1. Supporting the submission of the remaining FERC and permitting process through:

   a. resource reports (RR#2 to RR#12) which are primarily environmentally related;

   b. the revising and re-submittal of outstanding information in RR#1 following receipt of additional 2009 and 2010 survey data and development of the engineering;

   c. the response to questions and issues raised by FERC to the RR#1;

   d. input required for the filing of the FERC application; and

   e. data and information to support the state and federal ROWs and permit applications (such data is practically the same as that required by the FERC process and, as stated above, can be worked in parallel).

2. Developing the major deliverables associated with finalizing the FEED for the pipeline, AGIs and compressor stations to a level of detail that will facilitate the development of a +/-10 percent cost estimate.

3. Following the "open season" and the commencement of detailed engineering, the engineering will progress so that the following major contracts and long-lead

purchase orders kick-off immediately following final investment decision ("**FID**") and the notice to proceed:

a. Numerous pipeline installation contracts. It is envisaged that the 806 miles of pipeline will be constructed in five sections (or spreads). However, due the financial commitment each of these "spreads" requires it is envisaged that they will be subdivided into a number of subcontracts, the scope and commercial structure of which will be developed as a key activity during the Pre-FEED. Potential activities to be separated in this way may include:

    i. gravel Mining and hauling;
    ii. road construction;
    iii. work pad construction;
    iv. trenching/welding and backfilling;
    v. camp construction and maintenance.

    As it is planned that the detailed design of the Pipeline will be completed and that all major materials will be procured and free-issued to contractors, the strategy is to award simple procurement and construction contracts whereby the contractor will be responsible for the procurement of consumables and bulk materials. In order to ensure that the contractors are fully aware of the NTP applications and award process (many of the applications will be submitted and approved after FID); it is proposed that these contractors should be fully onboard prior to FID and that the contractors are fully engaged in the process and understand and accept accountability for meeting the constraints.

b. A single compressor station engineering/procurement and construction contract. As in the case of the Pipeline, the engineering for the compressor station will be at a very high level and will only require adaptation by the Project team to include any requirements imposed by the FEIS, FERC or the NTPs prior to final award.

c. A contract for the design and supply of the SCADA and communication system, based on a functional specification and philosophy developed during the development phase. By the end of the development phase, the I/O count should be at 90 percent complete or better, as all the P&IDs will have been developed.

d. Purchase orders for line-pipe, pipeline compressors and large pipeline valves.

These deliverables will include all the data gathered by the various detailed engineering surveys, as well as the numerous environmental surveys and studies conducted in 2009 and 2010. It also will encompass any restriction and requirements from the EIS, as well as providing responses to questions raised by the publication of the DEIS.

2.2.1.2(h) Execution Philosophy Post-FERC Application for the Pipeline

Once the FERC application has been successfully submitted, the Bechtel PMT will remain available to assist with the process leading up to issue of the DEIS issue, by responding to questions raised by FERC and/or the EIS consultant.

2.2.1.3 LNG Facilities – Engineering

2.2.1.3(a) Description

- three LNG trains, each sized to produce a nominal 5 mmta, based on Phillips' optimized cascade process;
- initial site preparation will include land for four LNG trains;
- two LNG tanks each, 180,000 cm with provision for one additional future tank; and
- two LNG loading jetties.

2.2.1.3(b) Development Phase Objectives – LNG Facilities

The Project will be developed by using a proven execution methodology and LNG process template that provides basis for performing the detailed engineering, equipment and materials procurement and plant construction at Valdez. Bechtel's activities during the development phase will involve pre-FEED, FEED and supporting the Port Authority and its partners with the FERC applications. The pre-FEED activities will be directed to prepare the basic project definition and basis of design in support of RR#1. During the FEED, the remaining resource reports will be prepared or input will be provided to the environmental consultant who will prepare the resource reports.

2.2.1.3(c) Development Phase Schedule Impacts on the LNG Plant – LNG Facilities

The schedule allows nine months for pre-FEED and 12 months for FEED and although the topographic and geotechnical survey information being acquired during 2009 along with the submission of RR#13 are critical to the LNG schedule, Bechtel's standard LNG work processes should not be impacted significantly.

2.2.1.3(d) Execution Philosophy Pre-RR#1 Submission – LNG Facilities

The engineering plan during the pre-FEED will be developed to prepare documents required for RR#1 filing. This process typically requires:

- detailed description of the project and location map of the facilities;
- basis of design for the FEED, including site data such as geological surveys, geotechnical data, seismic conditions, etc.;
- plot plans and site layout plans of the facilities, including location of environmentally sensitive areas;

- construction methodology; and
- identification of construction permits.

The pre-FEED will also involve process design, optimization studies for driver selection, waste heat recovery, site development issues, layout, local infrastructure and labor surveys, etc.

2.2.1.3(e) Execution Philosophy For RR#13 Submission – LNG Facilities

A detailed engineering and design will be developed during the FEED that meets the requirements of RR#13. The engineering plan will typically include:

- detailed plot plans with location of all major equipment, product storage/loading facility, etc.;
- detailed layout of the hazard detection/mitigation systems, spill containment system, fire protection system, seismic risks, etc.;
- over-pressure relief and plant safety philosophy;
- process conditions and technical data for major components of the plant;
- PFDs, and piping and P&IDs;
- process control philosophy and technical data for key instruments;
- technical data on electrical power generation and distribution systems, emergency/back-up systems, etc.;
- minimized environmental impacts and development of preliminary mitigation plans and measures;
- manuals/drawings for LNG storage tanks;
- a list of all applicable design codes and standards, including compliance to NFPA 59A and 49 CFR 193; and
- a list of all permits or approvals from federal/state/local agencies, Native American groups, etc.

The FEED will include additional deliverables not listed above; some of the major ones are shown below:

- design basis manual for EPC;
- process/utilities optimization and heat and material balances;
- equipment loadsheets/datasheets;
- chemicals and catalyst list;
- codes and specifications for equipment (mechanical, electrical, instruments), piping, civil, coatings, welding, marine, etc.;
- drawings (PFDs/P&IDs, schematics/layouts, piping design, control loops, etc.); and
- EPC project execution plans, cost estimate and project schedule.

2.2.1.4 Project Development Phase Geotechnical Engineering

2.2.1.4(a) Introduction

Bechtel's Geotechnical Engineering Services group will provide specialized engineering services to support the Project. The group's primary goal is to provide identification of surface and subsurface conditions and evaluation of engineering properties in support of civil/structural and pipeline group design efforts. The group has two primary components; geotechnical and marine services.

Geotechnical services include subcontracted in-situ drilling, sampling and testing as well as in-house geotechnical engineering of the site-specific data. The typical scope of work includes developing site investigation plans, developing associated technical contract documents, completing engineering assessments and reports. The preliminary work is followed with supporting project and civil/structural and pipeline engineering during design and implementation during construction. A group of geologists will supplement the geotechnical group effort on an as-needed basis.

Marine services include obtaining subcontracted metocean data, evaluation of relevant marine and climate data to assist in designing port/harbor marine facilities associated with oil, gas and chemical projects. These can, as appropriate, include scope definition, berthing studies, jetty layout and design, breakwater evaluation and design, and related design issues.

2.2.1.4(b) Philosophy

A phased approach is being developed for the proposed Project (including the LNG Facilities). Initial field investigation efforts will be primarily based on remote geophysical, aerial and satellite imagery technologies. The results of these remote-sensing methods will be used to identify physical locations for the second (detailed) phase of investigation.

Planning for the initial surveys would begin after April 1, 2008. The scope for detailed surveys will be developed based on the results of the initial surveys and are expected to be conducted during 2009 and 2010. Some supplemental surveys consisting primarily of limited soil borings may be conducted simultaneously with the initial surveys during the first summer (2009) season.

2.2.1.4(c) Initial Survey

Historic information, including soil borings and other soils investigation data, will be available from the YPC data and public sources. Such data would be collated and provided by the Alaskan authorities and made available to the project for review and use in establishing the initial project basis and design on which the RR#1 will be founded.

Simultaneously with the review of historic information, subcontracts will be issued for obtaining various geotechnical and geophysical data, primarily using remote-sensing technologies. These would include InSAR and Aerial Geophysical methods.

- **InSAR**. InSAR is a remote sensing tool that uses radar to measure land deformation. Typically, the radar is mounted on commercial satellites, and historic data is generally available for analysis. Proprietary software is used to detect displacement over the time interval between satellite record dates. The primary use of this technique would be to conduct historic analysis to discern areas of potential future movement or instability. Any areas identified would then be subject to more intense investigation during the development phase, following submission of RR#1.
- **Aerial Geophysical**. A helicopter-based electromagnetic/ground penetration radar survey is proposed. The technology is useful in mapping contrasts between conductive and resistive geological units, changes in soil geology, depth to bedrock and permafrost locations. The intent is to provide coverage over the pipeline corridor, as well as the LNG facility sites.

Other components of the initial survey will include:

- Geologic reconnaissance, site evaluation/survey of the proposed LNG site and compressor stations. In addition to a desktop survey and geological review, this will include a geological site walkthrough.
- Marine survey
  - Bathymetry
  - Offshore geophysical, which may include side-scan sonar, sub-bottom profiling and magnetometer surveys.
- Metocean study. This is an accumulation of existing, published metocean data, with interpretation, as required to make it applicable to the specific project site.

2.2.1.4(d) Supplemental Surveys

During the initial surveys, it is considered advantageous to make best use of the summer season to conduct conventional soil boring investigations. The intent would be to identify areas of confirmed interest, such as pump stations or facility sites, and to obtain initial boring information. Initially, this would concentrate on the compressor station locations and major river crossings, although both will be subject to any seasonal environmental limitations.

2.2.1.4(e) Detailed Surveys

Following evaluation of data from the initial survey, plans would be developed to obtain detailed information in areas of critical interest or areas without available historic geotechnical data. It is anticipated that such site investigations would be conducted during the second summer season (year 2010) and would cover areas such as:

- stream/river crossings;
- pipeline crossings;
- fault crossings;
- side slopes and other areas of potential instability, especially where they may impact the existing;

- permafrost areas; and
- heave zones.

2.2.1.5 Project Development Phase – Procurement

2.2.1.5(a) General

The Project procurement team will perform purchasing, expediting, supplier quality, traffic and logistics, material management, and procurement automation as required for the development phase of the pipeline portion of the Project. The group will use the standardized work processes, procedures, systems and integrated tools that form the basis of Bechtel's world-class procurement capability. The procurement personnel assigned to the project will have experience working in both the domestic and global markets.

The project procurement team will perform the following commercial activities during the development phase of the project:

- Develop a detailed procurement strategy and execution plan. This will recognize any standardization/harmonization needs across the project and any consequences this may have for the module suppliers and contractors.
- Identify risk(s) associated with schedule and cost and develop a mitigation plans to manage these risks(s).
- Identify lead times for all equipment and materials, including bulks.
- Identify and develop the proper controls for equipment and materials impacted by federal import compliance procedures.
- Price equipment and materials to support an estimate utilizing Bechtel's market knowledge and commodity expertise to support a +/- 10 percent estimate at the end of FEED.
- Identify critical long-lead delivery items, including tanks, linepipe, compressors and pipeline valves. Solicit bids and negotiate/award. Awards will only be made where:
  - time can be saved by executing early engineering;
  - early engineering is require as it will impact/influence other engineering/construction/logistics activities; and
  - early engineering is required to support the EIS process by either providing definition or solutions to issues.
- Conduct a traffic and logistics survey of the site area, and develop a traffic and logistics plan. Develop a freight estimate utilizing T&LS robust work process to ensure low cost.
- Perform supplier/shop/company visits/surveys to understand and utilize Alaskan businesses and supplies by performing supplier/shop/company visits/surveys.
- Develop mechanisms for the early engagement with supplier(s) so that:
  - supplier specifics are included in to the design;

- any limitations/requirements imposed by the EIS/Permitting process are understood and accommodated;
- any supplier limitations/impacts are understood and accounted for.

2.2.1.6 Commissioning and Start-Up

2.2.1.6(a) Development Engineering Phase Activities

The C&SU team will be initiated during the development phase to:

- ensure that the engineering design includes input for proper operation, maintenance and startup of the facilities;
- participate in hazard and operability ("**HAZOP**") reviews;
- advise engineering and procurement personnel so adequate commissioning spare parts are procured in a timely and cost-effective way;
- prepare the preliminary pre-commissioning/commissioning manuals;
- prepare a first draft of the operations manual;
- prepare the safety plans for pre-commissioning and commissioning;

identify systems in a logical sequence for a safe start-up of the facility; and

prepare a pre-commissioning, commissioning, startup and turnover schedule.

2.2.2 Stakeholder Issues Management Plan

2.2.2.1 Introduction

The Project, which will involve the construction of an 806-mile pipeline that traverses the length of Alaska, together with the construction of gas conditioning facilities at Prudhoe Bay and gas liquefaction and processing facilities in Valdez will be the biggest construction project in the United States. Careful planning and coordination with all stakeholders will be of utmost importance during the Project development phase to ensure that (a) the benefits associated with the Project are maximized; and (b) the negative impact of construction activities are minimized.

A key objective of the Project stakeholder issues management plan ("**SIMP**") is to establish effective means of communication in order to ensure the stakeholders are well informed about Project activities and that the Project team is conversant with, and can respond to, manage or mitigate stakeholder concerns.

The key stakeholders in the Project include:

- U.S. military landowners along the Pipeline right-of-way, including the U.S. Department of Defense, U.S. Air Force and U.S. Army
- the U.S. Park Service
- individual Alaskan landholders, as well as Alaska Native Corporations
- Political subdivisions of the state, such as the North Slope Borough, the Fairbanks North Star Borough, the City of North Pole, the City of Valdez, Delta Junction, Glennallen, Anchorage, and other communities
- the U.S. federal government
- Alaska emergency service providers
- Alaska State Troopers
- labor organizations
- recreational land users
- non governmental organizations (NGOs)
- oil industry
- the University of Alaska
- education/training providers
- resource developers, contractors, and material and equipment providers
- the general public
- utilities

Landowners in the Pipeline right-of-way include:

- Ahtna, Inc. (Native Corporation)
- U.S. Department of Interior, Bureau of Land Management
- Black Rapids Training Site
- Chena River Lake Flood Control Project
- Eielson Air Force Base
- Fairbanks North Star Borough
- Golden Valley Electric Association
- Mental Health Land Trust
- Municipality of Valdez
- Private Land Owners
- Private – Alaska Native Allotment
- Private Mining Claim
- Private Subdivision
- State of Alaska

- State Subdivision
- U.S. Army Corps of Engineers
- U.S. Forest Service

Upon award of the AGIA License, the Port Authority will appoint a SIMP manager to begin a coordinated implementation of the SIMP by:

(1) Establishing, within the Port Authority's internet website, a Project overview citing specific timelines for the Project. In addition, the website will request that stakeholders forward their concerns or questions to the SIMP team for evaluation and/or response. The website will enable stakeholders to provide input on a continuous basis. This approach will be similar to a web-question/answer approach used with RFA inquiries under the AGIA application process.

(2) Compiling a list of individual representatives of all the major stakeholders within the first 30 days after License award. The goal will be to ensure that all major stakeholders have a representative to act as a liaison with the Port Authority. Communication, at a minimum, with such representatives will be through a regular email update addressing major developments with the Project.

(3) Establishing within 60 days of License award, an advertising and marketing campaign designed to inform all identified stakeholders and the public about the Project. The campaign will be conducted via print, broadcast, and electronic media, as well by targeted direct mail. The advertising campaign will cover local, regional, national and international audiences.

(4) Scheduling and conducting public presentations and hearings in municipalities and other areas of population that would be affected by the Project, such as: Barrow, Coldfoot/Wiseman, Fairbanks, Eielson Air Force Base, Delta, Fort Greely, Paxson, Glennallen, and Valdez, and Anchorage. Other communities and villages will be identified via the public input/outreach process.

(5) Responding to input received from the public hearings within 30 days of the close of the proposed public comment period.

(6) Holding a second round of public hearings, three to six months later, with a special emphasis on presenting how the Port Authority has addressed the received public comments and concerns and to accept additional input.

(7) Incorporating additional relevant and beneficial input received into Port Authority planning.

2.2.2.2 Land-Based Interests

A list of land owners along the Project route is provided in Appendix J.

The communities identified along the Project route consist of the following:

- North Slope Borough, including the villages of:

  - Anaktuvuk Pass
  - Barrow
  - Kaktovik
  - Nuiqsut
- Between the North Slope Borough and Fairbanks North Star Borough:
  - Wiseman
  - Bettles / Evansville
  - Allakaket / Alatna
  - Stevens Village
  - Rampart
  - Minto
  - Livengood
- Between the Fairbanks North Star Borough and Valdez:
  - City of Fairbanks
  - City of North Pole
  - Delta Junction
  - Fort Greeley
  - Glennallen / Copper Center Area
  - Valdez

2.2.2.3 Recreation, Aesthetics, and Wilderness

2.2.2.3(a) Introduction

As with many other aspects of the Project, there would be both positive and negative impacts on recreation, wilderness, and aesthetics. Generally, the negative impacts would emanate from construction noise, dust, and visual scars on otherwise undisturbed and natural areas. New recreation access points would be created by the Project. Greater numbers of people would reside in the State.

Recreational use along roads associated with this route from Livengood south to the Valdez area is heavy and would be impacted primarily during construction by competing uses between tourist and construction workers, since most popular recreation facilities are highway oriented.

2.2.2.3(b) Recreation

The area from Chandalar Shelf north to Prudhoe Bay at present has only light recreation use, consisting mainly of fly-in hunting and fishing. Several hunting guides operate from airstrips near TAPS, especially the Galbraith Lake and Sagwon airstrips. Recreational use along the Dalton Highway would also increase due to the number of construction workers. Impacts on recreation would be expected to be moderate.

The proposed Pipeline route runs parallel to, or a few miles from, a highway system along its entire route. Lateral access roads from the existing highway to the proposed route would, if open to the public, very likely be used by recreationists. This access would extend the area and amount of use that already exists and could significantly increase the recreational opportunities.

Examples of potential openings of new access to presently roadless areas would include: the west side of Atigun River above Galbraith Lake, Summit Lake and Grayling Lake. Impacts would be moderate on these areas. The Galbraith Lake and the Sukakpak Mountain areas are well-known entrance points to the nearly Brooks Range federal conservation units, including Gates of the Arctic and the nearby Arctic National Wildlife Refuge.

During construction there would be moderate recreational use of areas along the pipeline by construction workers. Recreation opportunities for travelers and vacationers on highways along the route would be temporarily altered during the construction period. However, there would be moderate, increased use by construction workers and others in the winter months where roads are kept open and maintained, resulting in minor impacts to recreation.

Unless steps are taken to provide adequate recreation facilities, campgrounds, picnic areas, overlooks, boat access sites, trail leads, parking areas, turnouts, and rest stops, damage to the vegetation and trash from uncontrolled recreation use and a general degradation of recreation and aesthetics would result. Additionally, due to the typical influx of tourists to Alaska and the presence of the construction workers and their families, the increased use of public campgrounds could cause an increased potential for human/carnivore interaction due to feeding by the visitors and poor handling of garbage and other attractants. An example of a closing of a public campground occurred during the construction of TAPS when the campground on the Upper, Little Tonsina, near Pump Station Number 12 where marauding bears became habituated to humans.

Odors from engine exhaust, fuel areas, and camps would be evident near recreational areas during construction.

Wildlife populations near the corridor would be temporarily affected by the construction of the proposed project and possibly by increased pressure from hunting and harassment by workers.

Unregulated use by all-terrain vehicles, trail bikes, snowmobiles, and other off-road vehicles could have a significant adverse impact on recreation and aesthetics by permanently scarring the landscape, damaging the vegetation, compacting the soil, causing erosion, and harassing the wildlife. These activities would probably continue to be restricted by the State as they presently are along the Dalton Highway. Therefore, the impacts would be minor.

Project-related recreational needs would increase potential for recreational use of the area because more people would become aware of such opportunities through publicity and personal association with employees. More use would inevitably bring more control; thus, present recreationists might experience such things as reservation systems, reduced options for types of experiences, and restrictions on places they might go and heir length of stay. Additionally, the tourism industry expansion would be curtailed in certain areas during construction, especially at major interest points such as Keystone Canyon and Worthington Glacier.

2.2.2.3(c) Aesthetics

Aesthetics is a value judgment; everyone interprets and experiences it differently. Some would view the project's increased availability of a unique area to more people to be a benefit while others would say it is an intrusion.

A more direct impact of construction on recreation resource would be the visual scars resulting from buried pipeline construction and the visual impacts of aerial stream crossings. In all cases this gas pipeline would be at least a third utility and perhaps a fourth to be located in the corridor area; consequently, it would not be the same as building a new pipeline across an undisturbed area.

Facilities such as communications towers, buildings at compressor sites, block valves, and the LNG site, would be visible from the air and highway for great distances in some cases. At times, the linear pipeline berm would also be visible to those hiking in the nearby mountains. Lights on communications towers and at compressor stations would be visible over long distances, especially at night. Impacts would be minor to moderate along the corridor. Co-use of existing facilities such as communications facilities would result in no impact.

Nearly all of the proposed right-of-way south of the Brooks Range would require the clearing of brush and forest cover. This would significantly alter the natural environment and in these areas would degrade existing aesthetic values, particularly where long straight clearings are visible from the road. These impacts would be moderate during construction and minor during operation.

Recreationists within several miles of the line would have their experiences affected by construction and operation activities. When the route passes within a mile or so of presently used recreational areas, the impacts would typically be minor, especially during construction. Noise, traffic, additional dust, and the scars from clearing and ditching would decrease the experience, sometimes to a considerable degree. Impacts in the vicinity of TAPS during construction would be moderate and negligible thereafter.

Many of the aesthetic impacts have already been discussed under recreation. The major impact to many people would be the viewshed as seen during hiking, driving on the main roads, and boating on rivers as well as from the air. For those people whose appreciation of aesthetic quality is related to beauty, sensations, or to the congruity of the environmental features, the proposed project would have a major adverse effect on the resource. Visual impacts in forested areas are particularly severe and long-term in areas of high relief or low vegetation. The pipeline right-of-way, borrow sites, cut and fills, and access roads would remain landscape features indefinitely causing long-term aesthetically adverse impacts. But for others, long tangents might add interest to otherwise repetitive, though natural views.

2.2.2.3(d) Wilderness

The preferred pipeline routing involves two small areas where existing wilderness studies and recommendations to Congress have not been completed. YPC has previously identified optional routing at MP 95 and MP 110 that would avoid areas "having wilderness values." These optional routings are specifically incorporated into the Project EIS. There are several federally designated wilderness areas near the route, including the Arctic National Wildlife Refuge, the Gates of the Arctic National Park and Preserve, and the Wrangell-Saint Elias National Park and Preserve, which are primarily roadless and wilderness areas. None of these areas would be directly disturbed by the proposed project. Impacts should be minor. There would be some increased use of wilderness areas in Alaska as a result of construction and operational employment opportunities created by the Project.

2.2.2.3(e) Wild Rivers and Chugach National Forest

There would be no direct impacts to the Gulkana and Delta Wild and Scenic River areas since the route would not cross the designated portions of these rivers. Units of national park and refuge systems authorized by ANILCA are not involved. The portion of the LNG terminal buffer area within the Chugach National Forest is classified as a general multiple-use forest area. Secondary impacts to these recreation areas would occur due to construction workers using recreational areas. Also, the buffer area for the LNG terminal that is in the Chugach National Forest has been transferred by the USFS to State ownership under the Alaska Statehood Act.

2.2.2.3(f) Valdez Area

Most recreation in the Valdez area is centered around fishing; sightseeing by car, boat, and by foot; and some hunting. These recreational pursuits would be stressed considerably during construction due to the large influx of people to an area with limited accessibility. The aesthetic experience of fishing for anadromous species such as salmon would be impacted, but there are other factors which affect these activities more than crowded stream access points.

Hiking opportunities should be increased after construction, especially in such areas as Keystone Canyon where accessibility to trailheads would be somewhat improved. The locally popular Goat Trail and Bridal Veil Falls would be affected only during the construction period. Aesthetics of this region would be only moderately affected once construction was completed.

2.2.2.3(g) Summary

The impacts to recreation and aesthetics would be widespread due to the length of the area disturbed, but the band of disturbance would be quite narrow.

Primary disturbance would occur during construction and would involve impacts to present uses and users of the area, especially by tourists, sightseers, and wilderness enthusiasts. During construction we anticipate the following short-term impacts on tourism:

- increased highway traffic
- increased air passenger activity
- shortage of hotel and other visitor accommodations
- problems hiring and retaining tourism service employees due to the attraction of higher paying pipeline jobs

However, these impacts should be offset by the following:

- The airlines will likely add more flights.
- The year-round occupancy rates should be significantly higher, thus increasing bed tax revenues (where applicable), which are used primarily to support tourism promotion and development efforts.
- Prudhoe Bay, the TAPS pipeline, and Valdez Marine Terminal are major tourist attractions.
- Improvements in the transportation infrastructure will be of long-term benefit to the tourism industry.
- Increased state and local government revenues from the Project can be used to advertise tourism and finance development projects.

Impacts to aesthetics would be more long-lasting. The visual impacts would include long stretches of linear clearing of vegetation and many new borrow sites where vegetation has been removed. Their impacts would be moderate.

There would be negligible impact on wilderness value since the band of increased disturbance is quite narrow and would not change the existing character of a majority of the route.

2.2.3 Commercial Plan

The Port Authority has begun discussions with Alaska Regional Native Corporations, whose land the pipeline will cross, with the goal of facilitating the formation of a consortium consisting of Native Corporations to work with the operator and maintenance entity of the pipeline. While there will also be a role for an out-of-state consortium partner with significant pipeline operation experience, it is the goal of the Port Authority to allow the Regional Native Corporations to have the maximum opportunity available to assist that role. Alaska has matured significantly since TAPS was constructed and operations began. The Port Authority believes the local Regional Corporations should be provided the first opportunity to assemble their own team to perform these functions where possible.

2.2.3.1 Plan Prior to Open Season

A detailed description of FEED, field work, and other technical activities planned for the period prior to the initial open season for the Project, as required under section 2.2.3.1 of the RFA, is provided in Section 2.2.1 and the introductory portion of Section 2.2 above.

2.2.3.1(a) Description of Steps and Strategies to Facilitate a Successful Initial Binding Open Season

The Port Authority has developed the following strategies to facilitate a successful initial binding open season:

- The Project gas throughput volume, at approximately 2.7 bcfd, is such that the Project can proceed without the discovery and development of additional ANS gas reserves. The successful implementation and financing of other proposed projects that assume larger initial throughput volumes will require gas throughput commitments that are backed by sufficiently large gas reserves. For example, a proposed pipeline project to Canada with initial gas throughput volume of 4.5 bcfd would require approximately 50 trillion cubic feet ("**tcf**") of gas reserves under a 30-year project life. Such gas reserve requirements would be in excess of the 35 tcf of currently discovered ANS gas reserves. Therefore, adequate gas transportation commitments in an initial open season for such larger project may not be available until some time in the future when additional ANS gas reserves have been discovered and proven. The Port Authority's Project eliminates the risk of delay in the implementation of a successful initial open season due to insufficient gas supply availability.
- The Port Authority's Project is designed to accommodate the allowed AOGCC Rule 9[5] offtake rate of 2.7 bcfd for PBU. The size of the Port Authority's Project thus further reduces the risk of there being insufficient gas supply at the time of the initial open season.
- As the Project can go forward using only Prudhoe Bay gas, the Project will not be subject to the risk of delays associated with the need to undertake a gas cycling project in Point Thomson.
- The Project size also eliminates concerns associated with marketing larger volumes of gas. Unlike, for instance, a 4 bcfd project to Alberta or the U.S. Midwest, participants in an open season need not worry about over supplying regional markets or associated price declines.
- Premium prices for LNG will result in high netback prices and strong returns for ANS producers, resulting in a strong commercial incentive for prospective shippers to participate in the initial open season.
- The Port Authority recognized several years ago that a key piece to the success of any Alaska gas pipeline project was the willingness of Point Thomson working interest owners to develop the field's resources and commit gas to a transportation project. Section 3 below explains that by terminating the former Point Thomson unit and underlying leases, the State is in the position to demand development on its timeline. The Port Authority thus views the Point Thomson 8 tcf of gas resources as potentially available to the Project upon receipt of the License.

[5] AOGCC Rule 9 of Conservation Order 341D: "The maximum annual average gas offtake rate is 2.7 billion standard cubic feet per day."

2.2.3.1(b) Contingency Plans to Obtain Commitments in a Successful Initial Binding Open Season

Like the State, the Port Authority is hopeful that the Prudhoe Bay working interest owners will abide by the terms of their leases and participate in an initial open season. Given the Project's compelling economics and this Administration's handling of Point Thomson, the Port Authority is confident that the Administration will provide appropriate encouragement to the working interest owners in Prudhoe Bay to participate in an open season.

2.2.3.2 Plan for Open Season

The Port Authority recognizes that certain Alaskan pipeline projects are subject to the FERC rules that govern their open-season procedures.[6] These procedures apply only to a "natural gas pipeline system that carries Alaska natural gas to the international border between Alaska and Canada (including related facilities subject to the jurisdiction of the Commission) that is authorized under the Alaska Natural Gas Transportation Act of 1976 or section 103 of the Alaska Natural Gas Pipeline Act."[7] Because the Project does not meet this definition, FERC's open-season regulations may not apply to it.

Nonetheless, the Port Authority contemplates complying with FERC regulations in order to minimize the risk of delays to the Project as a result of jurisdictional uncertainty and dispute. Furthermore, complying with FERC regulations will ensure that ANS gas producers who transported gas through the Project will have the option to market LNG for consumption in North America, in addition to the principal target markets in East Asia.

The Port Authority will hold an open season designed to meet the following key objectives: (a) facilitating the timely development of an Alaska natural gas transportation project; and (b) encouraging the exploration for new gas reserves by assuring competitive access to the pipeline.

The process will seek to secure binding bids for capacity on the Pipeline. The Port Authority is committed to awarding capacity to shippers on a nondiscriminatory basis.

The Port Authority plans to conduct its open season as follows:

- The Port Authority will seek an aggregate volume commitment from shippers sufficient to cover: (a) 100% of the feed gas requirements of the LNG facility in Valdez; and (b) the projected in-State gas consumption needs. A study of gas demand for in-State consumption will be performed during the development phase of the Project. The Pipeline will be designed to accommodate such in-State gas consumption needs.

---

[6] See 18 CFR Subpart B (§ 157.30, et seq.). See also Regulations Governing the Conduct of Open Seasons for Alaska Natural Gas Transportation Projects, FERC Stats. & Regs., Regs. Preambles ¶ 31,174 (February. 9, 2005); 70 Fed. Reg. 8,269 (February 18, 2005) ("Order No. 2005") and Regulations Governing the Conduct of Open Seasons for Alaska Natural Gas Transportation Projects, FERC Stats. & Regs., Regs. Preambles ¶ 31,187 (June 1, 2005); 70 Fed. Reg. 35,011 (June 16, 2005) ("Order No. 2005-A").

[7] Id. at § 157.31(a) (2006).

- Shippers will be required to include the location of the requested receipt point, volume, term and rate.
- The Project could be revised if the level of shipper interest indicates that the Pipeline's capacity should be adjusted.
- Bids will be evaluated on the net present value of the reservation charges offered. Shippers with the highest net present value bids will be awarded capacity. The Port Authority may reject bids below a certain rate floor.
- If the Port Authority receives more acceptable bids than available capacity, the Port Authority will consider increasing the Project's capacity. The base case Project design enables a capacity expansion through additional compression at a relatively low cost over the initial cost of the Pipeline.
- The Port Authority will consider bids that are non-conforming.
- The Port Authority intends to assess creditworthiness according to the standards adopted by Moody's and Standard & Poor's.
- If the bids in the open season are insufficient to justify the project, the Port Authority will talk with prospective shippers to market the capacity actively so that the Project may move forward.

2.2.3.3 Precedent Agreements

The precedent agreement is under development. It will address key commercial issues as follows:

- The Port Authority will agree to construct facilities if it receives sufficiently binding commitments to support the economics of the Project and receives all necessary permitting and regulatory approvals.
- Termination rights would relate to the timing for all permitting and regulatory approvals necessary for the project and the substance of those approvals.
- With respect to termination fees, the Port Authority may seek liquidated damages from shippers that terminate. The Port Authority would return any credit support that it has received from shippers.

A preliminary draft of the precedent agreement is attached in Appendix H. This preliminary draft is for illustrative purposes only and is subject to change.

2.2.3.4 Proposed Services and General Tariff Terms

The Port Authority plans to provide firm and interruptible transportation services. The Port Authority's terms and conditions of service are in development. It is expected that the Pipeline's tariff and terms and conditions of service will be similar those commonly employed in lower 48 interstate pipelines.

However, the Port Authority's tariff will be modified to reflect differences in regulatory regimes and specific needs of the project. For instance, FERC requires interstate pipelines to adopt standards developed by the North American Energy Standards Board (**"NAESB"**). However, certain NAESB standards may be meaningless for a pipeline that is not part of an extensive and interconnected interstate-pipeline grid. The Port Authority intends to provide prospective shippers with a draft of its terms and conditions of service during the open season. This will allow the Port Authority to work with shippers to determine whether any changes should be made.

2.2.3.5 Rate Structure and Supporting Information

For the purposes of this Application the Pipeline rates have been developed on the basis of a levelized cost-of-service methodology. The projected levelized rate is $2.54 per mmBtu of gas delivered to the LNG Facility in Valdez. Estimated fuel charges are 1.56% of quantity delivered. The financial model attached as Appendix NN provides the methodology of calculating the levelized rate.

The Port Authority notes that the Pipeline should have flexibility to offer negotiate rates with prospective customers, even if it also must offer a cost-of-service option.

In compliance with AS 43.90.130(10), the Port Authority commits to propose and support Pipeline rates that are based on a capital structure for ratemaking purposes that consists of not less than 70 percent debt. The assumed base case debt to equity ratio for the Pipeline at this time is 75:25.

The Port Authority further notes that new projects at FERC *have been authorized to apply* a 14% return on equity ("**ROE**") in their cost-of-service rates. Given that the Alaskan pipeline project would be a higher risk investment in comparison with recent interstate pipeline projects, the Port Authority believes that a higher return on equity may be required to attract outside private investors in the Pipeline project. Under the State ownership alternate option that is discussed in Section 2.8 below, the State may decide that it is in its best interest to keep pipeline tariffs low by accepting a return at the level of 14% or below.

2.2.3.6 Alternative Ratemaking Methods and Incentives

The Port Authority will consider alternative ratemaking methods as necessary to address the impact of cost overruns on the pipeline tariff, such as proposing negotiated and/or levelized rates.

Customary, non-levelized cost of service rates assume a straight line depreciation of the rate base and, therefore, the rates during the early years of a project's life may be significantly higher than those in later years. In contrast, levelized rates remain constant during the term of service, resulting in lower costs to the shippers in early operating years. Therefore, levelized rates provide higher shipper net cash flows in the early project life and, due to the time value of money, improve shipper returns. As the Project has a high capital cost, the negative effect of higher tariffs in the early years will be of particular significance for the value of ANS gas. Therefore, it is expected that levelized rates will be crucial in providing shipper incentives to participate in the initial open season.

In addition, the Port Authority may propose a capital cost-related adjustment to the return on equity component for ratemaking purposes, which will result in a shared risk of cost overruns between the Pipeline and the shippers, providing a strong incentive by the Pipeline entity to control costs. Under this approach, a sliding scale adjustment would be applied to the level of ROE used to calculate Pipeline rates, whereby a base ROE level is increased or decreased inversely with the increases or decreases in actual capital costs versus estimated costs. Such an adjustment was implemented, for example, for the Alliance Pipeline, a major natural gas pipeline transporting Alberta gas to markets in Canada and the U.S. The precise economic parameters of such rate adjustment provisions will be evaluated during the development phase, incorporating the cost estimates resulting from pre-FEED and FEED work.

2.2.3.7 Negotiated Rates

The Pipeline would have flexibility to offer negotiated rates with prospective customers, even if it also must offer a cost-of-service option.

The Port Authority anticipates that the alternative ratemaking methods discussed in Section 2.2.3.6 above would make the Project more attractive to prospective shippers and, therefore, anticipates that the majority of shippers would enter into negotiated rate arrangements with the Port Authority.

2.2.3.8 Anchor Shipper Incentive Rates and Commitments to Rates for Expansion Capacity

A discussion of shipper incentive rates is provided in Section 2.2.3.6 above.

2.2.3.9 Commitments to In-State Service

In accordance with the requirement set forth in AS 43.90.130(12), the Port Authority will commit to provide a minimum of five delivery points for natural gas within the State of Alaska, if it is awarded a license under the AGIA.

As required under AS 43.90.130(13)(A), the Port Authority commits to offer firm transportation service to delivery points in the State of Alaska as part of the tariff regardless of whether any shippers bid successfully in a binding open season for firm transportation delivery service points in the State, and commit to offer distance-sensitive rates to delivery points in this State consistent with 18 C.F.R. § 157.34(c)(8).

As required under AS 43.90.130(13)(B), the Port Authority further commits to offer distance-sensitive rates to delivery points in the State consistent with 18 C.F.R. §157.34(c)(8).

The Port Authority's approach has been to evaluate the benefits and costs of providing delivery points in-State. A guiding principle of the Port Authority is to ensure that communities, businesses, and State and Federal governmental entities across Alaska have access to clean burning, low cost, natural gas. The Port Authority's approach has been to evaluate the benefits and costs of providing delivery points in-State, with a particular focus on the communities through which the Pipeline will traverse.

As required under AGIA, the Port Authority commits to provide a minimum of five delivery and/or receipt points along the Pipeline, and will actively work to maximize the number of ultimate delivery points on a cost-efficient basis. One consideration that must be weighed when determining how many delivery points are installed is the balance between the investment that must be made to install a delivery point versus the expense of running natural gas spur lines. At some locations along the proposed route, it may be more cost-efficient if fewer delivery points are provided and other entities bear the expense of constructing additional miles of gas spur lines.

Provided below is a list of potential in-State gas consumption centers identified to date by the Port Authority.

2.2.3.9(a) Toolik Lake Research Station

Operated by the University of Alaska, the Toolik Lake scientific research station is funded primarily by the National Science Foundation ("**NSF**") and operates year-round. The station relies on Number-1 diesel fuel and is expanding. University of Alaska officials contacted by the Port Authority indicated they are highly desirous of replacing the 49,000 gallons of Number-1 diesel they purchase annually with natural gas. NSF funding may be available to them for infrastructure upgrades that will be necessary to convert to natural gas. Scientists conducting work at the research site are highly desirous of having a fuel source that burns significantly cleaner than the Number-1 fuel oil as the pollution from the fuel oil hampers scientific research conducted in the vicinity.

2.2.3.9(b) Wiseman

Wiseman is a small, unincorporated, community along the Dalton Highway.

2.2.3.9(c) Coldfoot

Coldfoot is the location of an Alaska Department of Transportation camp and truck stop at MP 175 of the Dalton Highway. This small community operates year round and is reliant on expensive fuel oil that is trucked from Fairbanks to generate heat and electricity. Representatives of the Alaska Department of Transportation indicated they very supportive of being able to obtain gas delivery points for their road camps.

2.2.3.9(d) Bettles, Allakaket, Alatna

Small, adjacent communities, near the Dalton Highway. The Port Authority proposes providing one delivery point in the region.

2.2.3.9(e) Stevens Village, Fort Yukon

These small communities are near the proposed pipeline corridor. The Port Authority proposes providing one delivery point at the closest point of the pipeline corridor to Stevens Village.

2.2.3.9(f) Yukon River

This is a hub/transit point where the Dalton Highway crosses the Yukon River. ANGDA has a proposal to build infrastructure at this location to ship gas/propane to many Yukon River communities.

2.2.3.9(g) Fort Knox

Fairbanks Gold Mining Inc. operates Fort Knox, the largest open-pit gold mine in North America and an important contributor to the Alaska's economy. The mine uses a substantial amount of power for their year-round operation. The Port Authority is in the process of determining the most economical location for a delivery point for Fort Knox. On possible location under consideration for a Fort Knox delivery point is Fox, Alaska – the same delivery point as for Fairbanks.

2.2.3.9(h) Fairbanks North Star Borough

The Fairbanks North Star Borough ("**FNSB**") is a large community of 86 thousand people that includes the City of Fairbanks, Fort Wainwright, Eielson Air Force Base ("**AFB**"), Ester, North Pole, and Fox within a borough that is the size of New Jersey. This borough will be a large consumer of natural gas in the Interior. The Port Authority envisions that the most likely delivery point for the City of Fairbanks, Fort Wainwright and the outlying Northern homes and businesses of FNSB will be in Fox, Alaska, where the pipeline infrastructure would pass closest to the City of Fairbanks.

2.2.3.9(i) North Pole, Moose Creek, Golden Valley Electric Association

North Pole and Moose Creek are small bedroom communities of Fairbanks. In addition, the Golden Valley Electric Association generates electrical power for the region from its North Pole facility. This generation facility includes turbines in North Pole that are designed to be able to run on natural gas.

2.2.3.9(j) Eielson AFB

Eielson AFB has a coal-fired power plant that is in very close proximity to the pipeline corridor. Two years ago, concern over the high costs of operating Eielson AFB was a major factor that led to a recommendation to the Base Realignment and Closure Commission that Eielson AFB be closed. The commission rejected the recommendation for closure, but Air Force officials are still concerned about the need to reduce costs. The more the costs of operating Eielson AFB can be reduced, the less likely it is that the base will be targeted for a closure in the future.

Eielson AFB is a key asset for the U.S. Air Force and an important economic engine for Alaska. Providing Eielson AFB with natural gas will reduce heating and electrical generation costs while also improving Eielson's air quality. Eielson officials contacted strongly support the delivery point.

2.2.3.9(k) Salcha, Alaska

Salcha is a distant bedroom community of Fairbanks and North Pole. A proposed delivery point will be near the Salcha Elementary School.

2.2.3.9(l) Harding Lake

Harding Lake is a distant community from Fairbanks and North Pole.

2.2.3.9(m) Pogo Mine

Pogo mine is an important new gold mine comprising about 16,700 hectares of claims and a reported gold resource of 5.6 million ounces. The mine is 85 miles east-southeast of Fairbanks on state land in the upper Goodpasture River Valley.

2.2.3.9(n) Delta Junction, Fort Greely, Donnelly Training Area

Delta Junction is a small, rural community. Fort Greely is a small U.S. Army base with significant energy needs. The Donnelly Training Area/complex has as many as seven hundred soldiers living in it during training exercises. U.S. Army officials who were contacted are desirous of replacing the 2.6 megawatts of electricity they purchase for the training area with low-cost natural gas.

2.2.3.9(o) Fort Greely Missile Defense Power Plant

This is the location of a land-based ballistic missile defense site, where a new power plant is to be constructed.

2.2.3.9(p) Glennallen

Glennallen is a rural community, which will also be the delivery point for the ANGDA spur line from Glennallen to Palmer to tie into the South Central gas grid, which would provide gas to the communities and consumers in the Matanuska Valley, Peters Creek, Chugiak, Eagle River, the Anchorage area and Kenai Peninsula.

2.2.3.9(q) Copper Center

Copper Center is a small rural community.

2.2.3.9(r) Valdez

Valdez is a mid-sized community and is also the terminus of TAPS. Valdez will also be the terminus of the All-Alaska Gasline and will be the major delivery point for gas transported for liquefaction at the LNG Facilities in Valdez.

2.2.3.10 Commitment on Rate Treatment of State's Reimbursement

In compliance with AS 43.90.130(18) the Port Authority commits that the State reimbursement received by the Port Authority will not be included in the applicant's rate base, and shall be used as a credit against the Port Authority's cost-of-service.

2.2.3.11 Minimizing the Effect of Cost Overruns on Rates

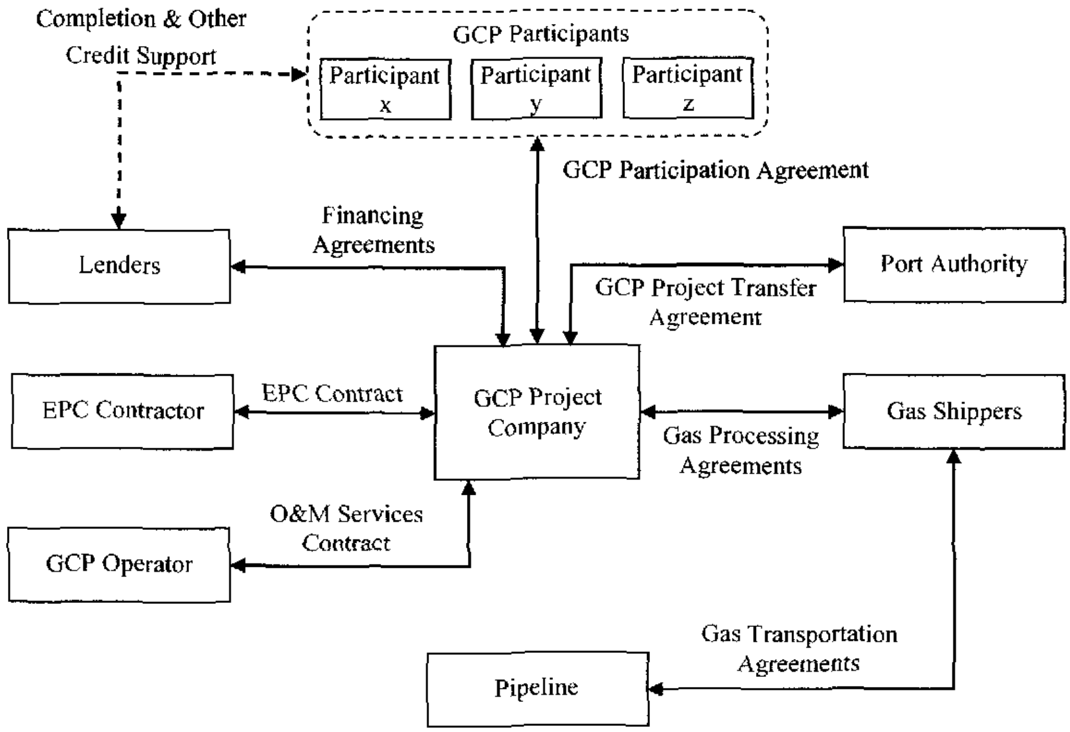
The Project will implement a range of customary methods and incentives to control Project costs and minimize the impact of cost overruns on the pipeline tariff, including entering into fixed-price, date certain EPC contracts for the major components of the Project, wherever possible, with limited price re-opener clauses. The contracting strategy will be designed to provide incentives on the part of the contractors for controlling costs. The Port Authority also expects to appoint an experienced engineering, procurement, construction contract manager (such as Bechtel) to assist in the management and coordination among the various EPC and EPCM contractors, among others.

Further, as discussed in Section 2.2.3.6 above, the Project would consider ratemaking methods, such as an adjustable equity rate of return, that would provide a strong commercial incentive to control costs and mitigate the impact of higher than budgeted costs on transportation tariffs.

2.2.3.12 Plan for the North Slope GCP

It is anticipated the commercial structure of the GCP will include the agreements as described further below in this section. Figure 8 shows a diagram illustrating the anticipated GCP commercial structure.

Figure 8 GCP Commercial Structure



The subsections below describe the key commercial agreements that are expected to be entered into with respect to the GCP.

2.2.3.12(a) GCP Participation Agreement

The GCP Participation Agreement will be entered into between the GCP Participants for the purpose of the ownership, development, construction, financing and operation of the GCP. The Port Authority is currently in discussions with a Regional Native Corporation as a potential GCP Participant. One or more of the ANS producers of natural gas, or their affiliates, may also be GCP Participants.

It is anticipated that the Port Authority will not participate in the GCP and that the gas processing services will be provided to the Project on a third-party basis. As such, the GCP has not been included in the proposed scope of the Project, as described in this Application.

The Port Authority has deferred negotiation with prospective GCP Participants until after award of the License, in order to achieve the most attractive commercial terms for the provision of gas conditioning services to the Project. It is anticipated that the execution of a definitive GCP Participation Agreement would be concluded prior to the commencement of the initial open season for the Project.

The GCP Project Participation Agreement will include, among other things, provisions specifying:

- the legal form of the entity that will own the GCP ("**GCP ProjCo**"), which may be a limited liability company ("LLC") or a similar entity;
- percentage shares, and voting rights of the GCP Participants;
- the governing and management structure of GCP ProjCo;
- procedures for entry of new GCP Participants and the exit of existing GCP Participants;
- procedures for cash calls to fund expenditures associated with the development, construction, financing and operation of the GCP;
- procedures for distribution of profits generated by the GCP; and
- any other provisions related to the rights and responsibilities of the GCP Participants.

2.2.3.12(b) GCP Project Transfer Agreement

Upon execution of the GCP Participation Agreement, the Port Authority and the GCP Participants would enter into a GCP Project Transfer Agreement, whereby the Port Authority would transfer to the GCP Participants, or their designee, its rights and obligations pursuant to authorizations, permits and commercial arrangements, as they relate to the GCP component of the Project, that have been acquired or entered into by the Port Authority up to the effective date of the GCP Participation Agreement.

2.2.3.12(c) Gas Processing Agreements

It is anticipated that GCP ProjCo will enter into Gas Processing Agreements with shippers of natural gas who have entered into gas transportation agreements with the Pipeline ProjCo and would require gas conditioning and processing services. Such agreements will define the terms and conditions of gas conditioning and processing services at the GCP for natural gas which will be transported on the Pipeline.

2.2.3.12(d) GCP Operations and Maintenance Services Contract

GCP ProjCo will enter into a GCP Operations and Maintenance Services Contract with an entity, which may be one of the GCP Participants or its affiliate, for the purposes of providing operating and maintenance services for the GCP.

2.2.3.13 Plan for Canadian Segment

A pipeline to Canada is not proposed for the initial phase of the Project and, therefore, a description of such a project segment is not provided in this Application. However, the Port Authority anticipates that in the future an AlCan Highway pipeline may be implemented and has designed its Project to facilitate and accommodate the development of such a pipeline.

The Port Authority views the All-Alaska Gasline as an initial "enabler" project for ANS natural gas development. The Project will take all available ANS gas not needed for oil reservoir pressure maintenance and other existing uses, and transport it to market in the form of LNG. It is anticipated that at some future point additional ANS gas will become available when it is no longer needed for oil reservoir pressure maintenance and that there will be additional commercial natural gas discoveries that will likely exceed the LNG liquefaction and distribution capabilities of the initial Project.

At that point in time, a likely expansion method for monetizing the full amount of known ANS gas resources and potential future gas discoveries, would be a "build-out" phase which would involve constructing an additional "Y-leg" pipeline from around Delta Junction to deliver these additional gas volumes into Canada along the Alcan Highway for ultimate tie-in to existing pipeline distribution systems delivering gas into Canada and the U.S. Midwest and West Coast markets. The Port Authority is committed to working cooperatively with the sponsor(s) of such a future Canadian pipeline project.

As there are many factors that determine the volume and timing needs for the Canadian pipeline, the Port Authority is not prepared to speculate as to when it might be constructed. However, Section 2.2.4 below addresses the major regulations applicable to such a "build-out" phase, including environmental permits and approvals potentially required for the Canadian portion of the project.

2.2.3.14 Plan for the LNG Project

The Port Authority is in discussions with several companies with strong track record and industry experience in the implementation of LNG projects and the marketing of natural gas, LNG and NGLs. It is anticipated that the LNG Facilities will be owned and operated by a venture consisting of one or more of these companies and, potentially, additional parties to be selected after award of the License (the "**LNG Participants**"). The LNG Participants will enter into an LNG Participation Agreement and establish the entity that will own the LNG Project facilities ("**LNG ProjCo**"), which could be an LLC or similar entity.

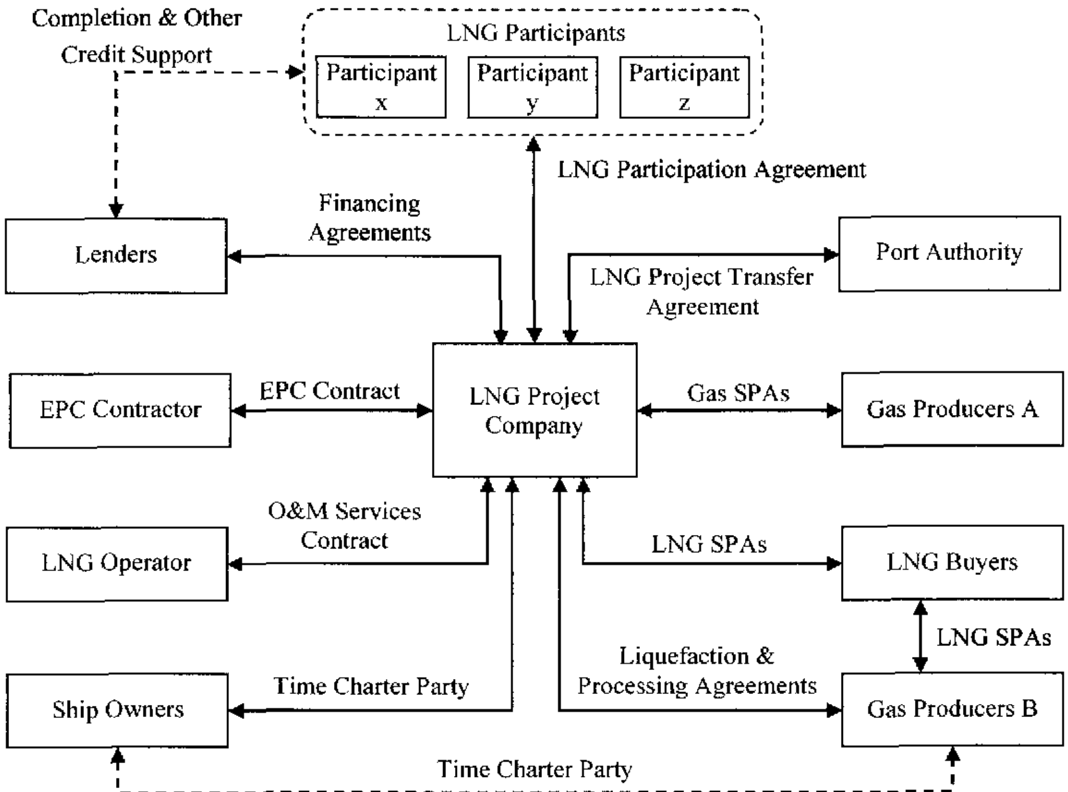
ANS producers who have arranged for transportation of natural gas on the Pipeline and wish to maintain ownership and marketing control over such gas downstream of the LNG Facilities, would enter into Liquefaction and Processing Services Agreements with LNG ProjCo, on a tolling basis, and would be responsible for marine transportation and downstream marketing and sales arrangements.

Natural gas that is not processed and liquefied at the LNG Facilities on a tolling basis pursuant to a Liquefaction and Processing Services Agreement would be purchased and marketed by LNG ProjCo and/or one or more of the LNG Participants pursuant to Gas Sales and Purchase Agreements. Sellers of natural gas under this arrangement may include ANS producers who do not have the expertise in marketing LNG in foreign markets.

The potential counterparties under (i) Liquefaction and Processing Services Agreements and (ii) Gas Sales and Purchase Agreements, and the allocation of the capacity of the LNG Facilities between these two types of commercial arrangements will be identified prior and during the initial open season.

Figure 9 below shows a diagram illustrating the anticipated commercial structure for the LNG Facility.

Figure 9 LNG Facilities Commercial Structure



The subsections below describe the key commercial agreements that are expected to be entered into with respect to the LNG Facilities.

2.2.3.14(a) LNG Participation Agreement

The LNG Participation Agreement will be entered into between the LNG Participants for the purpose of the ownership, development, construction, financing and operation of the LNG Facilities. One or more of the ANS producers of natural gas, or their affiliates, may also be LNG Participants. The Port Authority may retain a percentage ownership or other interest in the LNG Facilities, if it is determined to be beneficial to the structure and economics of the Project.

The LNG Participation Agreement will include, among other things, provisions specifying:

- the legal form of LNG ProjCo;
- percentage shares, and voting rights of the LNG Participants;
- the governing and management structure of LNG ProjCo;
- procedures for entry of new LNG Participants and the exit of existing LNG Participants;

- procedures for cash calls to fund expenditures associated with the development, construction, financing and operation of the LNG Facilities;
- procedures for distribution of profits generated by the LNG Facilities;
- any other provisions related to the rights and responsibilities of the LNG Participants.

2.2.3.14(b) LNG Project Transfer Agreement

Upon execution of the LNG Participation Agreement, the Port Authority and the LNG Participants would enter into an LNG Project Transfer Agreement, whereby the Port Authority would transfer to the LNG Participants, or their designee, its rights and obligations pursuant to authorizations, permits and commercial arrangements, as they relate to the LNG Facilities, that have been acquired or entered into by the Port Authority up to the effective date of the LNG Participation Agreement.

2.2.3.14(c) Liquefaction and Processing Services Agreements

The Liquefaction and Processing Services Agreements will be entered into between LNG ProjCo and third party shippers or producers of natural gas, including ANS producers of natural gas for the provision of liquefaction and NGL extraction services, on a tolling basis. Such agreements will include:

- specific volume requirements;
- length of term;
- tolling rates;
- "ship-or-pay" provisions;
- performance and default remedies; and
- any other provisions customary for agreements of similar nature.

2.2.3.14(d) Gas Sales and Purchase Agreements

The Gas Sales and Purchase Agreements will be entered into between LNG ProjCo, and/or one or more of the LNG Participants and sellers of natural gas, including ANS gas producers. Such sellers shall agree to sell to one or more of the LNG Project Participants, or to LNG ProjCo, natural gas transported on the Pipeline and delivered to the inlet of the LNG Facilities. The Gas Sales and Purchase Agreements will include:

- specific volume requirements;
- length of term;
- pricing arrangements based on applicable pricing indexes;
- "take-or-pay" and "supply-or-pay" provisions;
- performance and default remedies; and
- any other provisions customary for agreements of similar nature.

2.2.3.14(e) LNG Operations and Maintenance Services Contract

LNG ProjCo will enter into an LNG Operations and Maintenance Services Contract with an entity, which may be one of the LNG Participants or its affiliate, for the purposes of providing operating and maintenance services for the LNG Facilities.

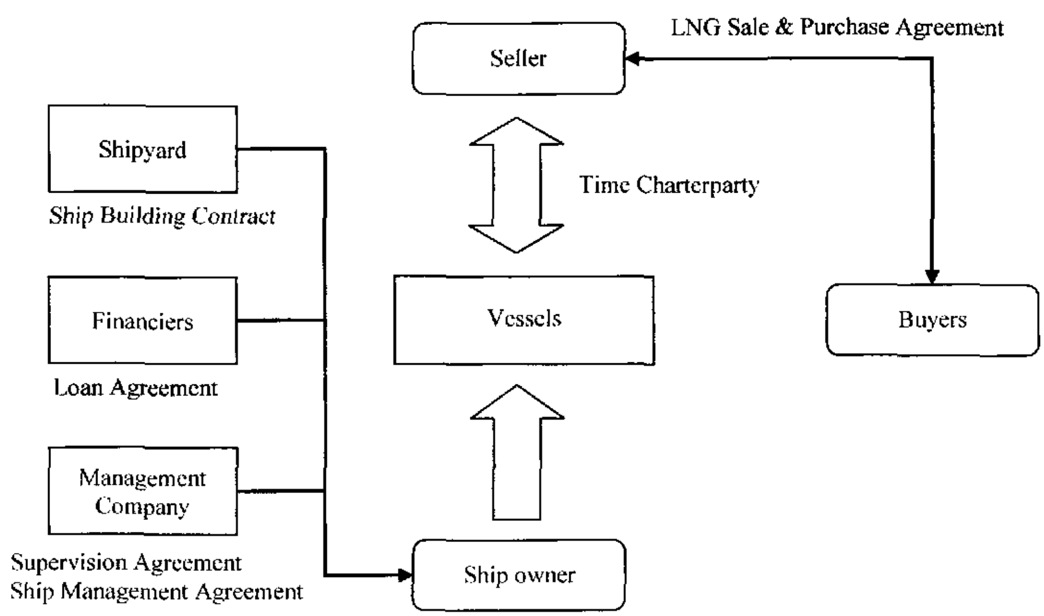
2.2.3.14(f) Commercial Plan for Marine Transportation Services

As described above in Section 2.1.3.2, marine transportation services for LNG and LPGs will be provided by third parties, who will be selected under a competitive tender process (the "**Ship Owner**"). It is anticipated that LNG ProjCo, and/or one or more of the LNG Project Participants will enter into marine transportation arrangements, such as long-term time charter agreements, for volumes of LNG that will be marketed by LNG ProjCo and/or one or more of the LNG Participants. As described in Section 2.2.3.14 above, such volumes of LNG will be produced from feed gas that has been purchased under Gas Sales and Purchase Agreements.

For volumes of LNG owned by third-party gas producers who have contracted with the LNG ProjCo for tolling services under Liquefaction and Processing Services Agreements and will maintain control over the marketing function themselves, the arrangement of marine transportation services will be the responsibility of such third party gas producers. It is anticipated that marine transportation for such volumes would be provided either by third party ship owners under long term charter contracts with the gas producers, or by the gas producers themselves, to the extent that they own their own tanker fleets.

Figure 10 below shows an illustration of a typical time charter structure for an LNG project supplying LNG to a buyer on a "delivered ex-ship" ("**DES**") basis, whereby the seller of LNG is responsible for marine transportation.

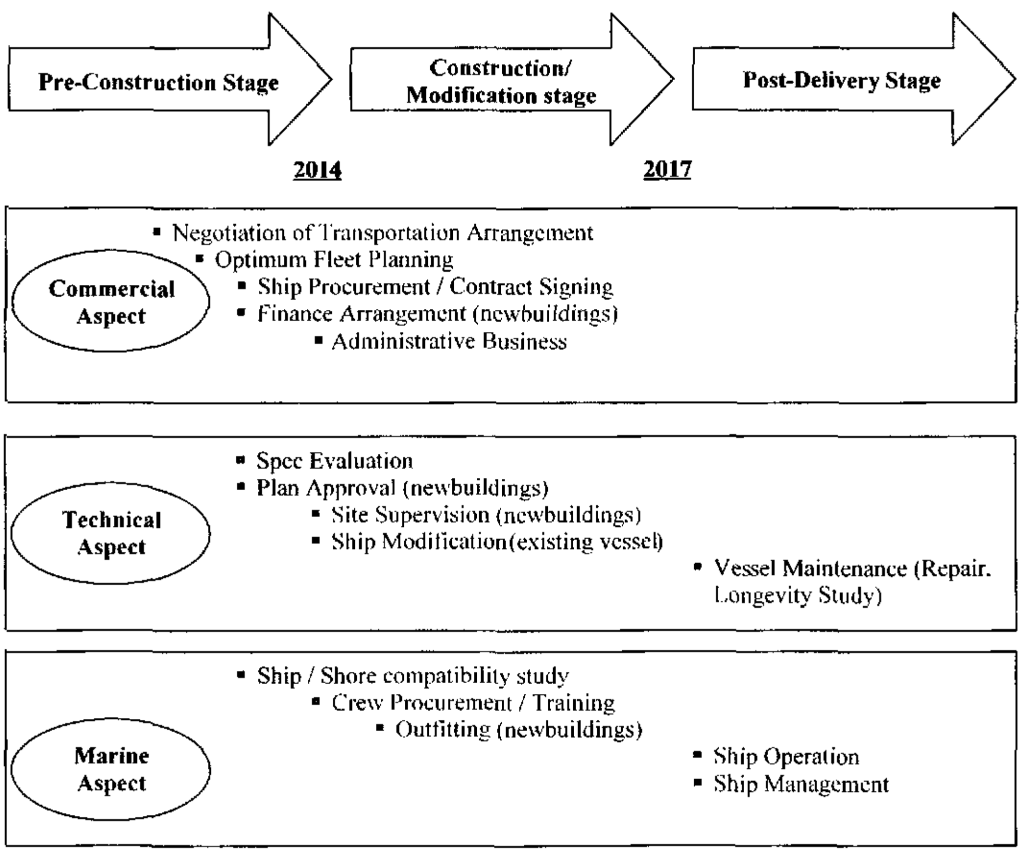
Figure 10 Indicative Time Charter Structure (DES Basis)



Under the commercial arrangement illustrated above, LNG ProjCo and/or one or more of the LNG Participants will act as the seller of LNG under LNG sales and purchase agreements with East Asian buyers, and also as the charterer under the time charter party agreement ("**TCP**") with the Ship Owner. The Ship Owner will enter into: (i) shipbuilding contracts ("**SBC**") with shipyards; (ii) financing agreements with lenders to provide debt financing for the vessels; and (iii) supervision and/or ship management agreement with a management company to manage the vessels.

The process of developing the marine transportation element of the project is illustrated in Figure 11 below. As the ship construction stage takes approximately three years, the SBC will typically have to be executed approximately 34-36 months prior to vessel delivery. The Ship Owners will enter into the shipbuilding contract on the basis of an executed long term TCP with the charterer. Therefore, the TCP would typically be executed by the execution date of the SBC.

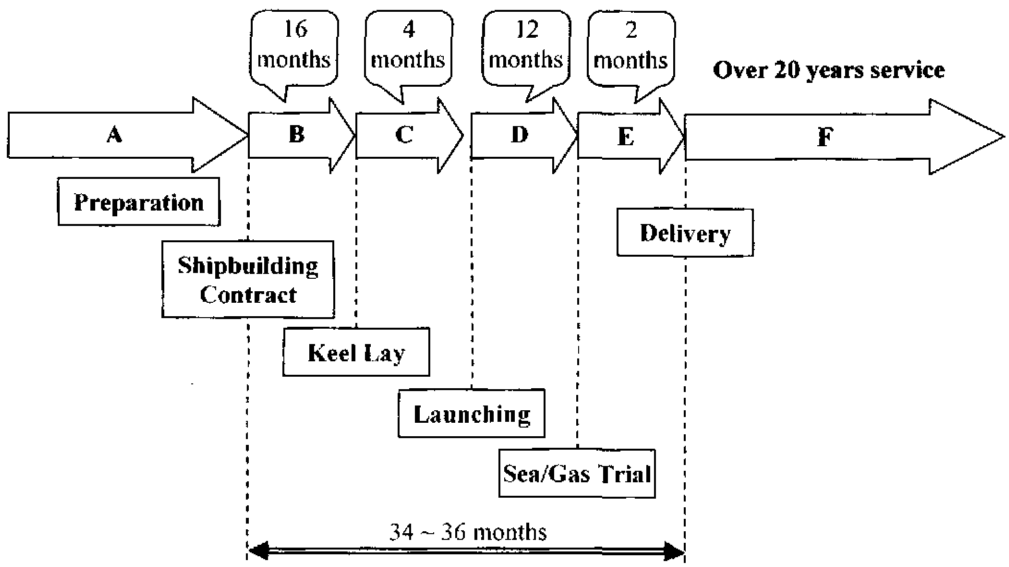
Figure 11 Marine Transportation Development Process



With an estimated Project startup date in 2017, the TCP and SBC would have to be negotiated and entered into by 2014, or approximately one year after the commencement of construction on the Pipeline, LNG Facilities and GCP.

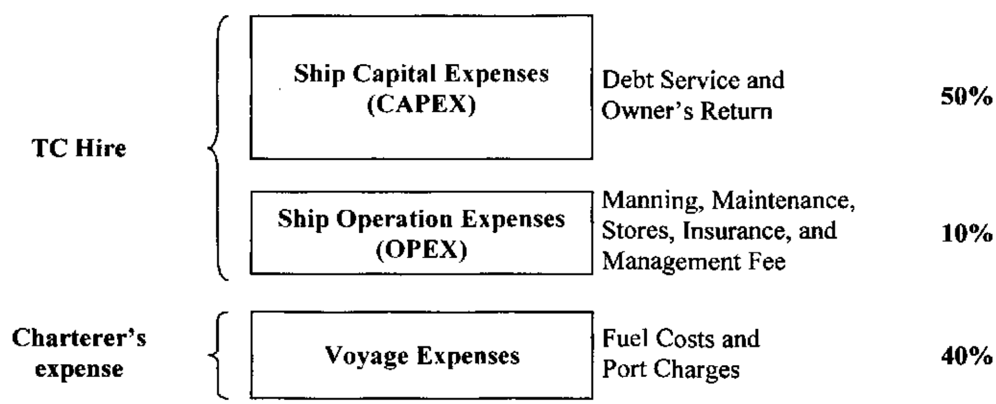
Figure 12 below shows an indicative construction schedule for LNG vessels.

Figure 12 Construction Schedule of an LNG Vessel



Under the TCP with the Ship Owner, the charterer will be paying the charter hire cost for the vessels, which consists of a capital cost and operating cost component. The charterer will also be incurring voyage costs, such as port charges and fuel costs. As illustrated in Figure 13 below, the capital cost component of the charter hire is typically the largest component of the marine transportation cost for newbuildings.

Figure 13 Marine Transportation Cost Components



Confidential estimates of the marine transportation costs for the Project have been provided by the MOL Companies and are attached as the confidential Appendix K.

The targeted destination markets for LNG are outside of the United States and, therefore, the marine transportation element of the Project will not be subject to the requirements of section 27 of the Marine Merchant Act of 1920, commonly referred to as the Jones Act.

To the extent that in the future some amount of LNG is directed to markets in the United States that requires, the Port Authority and the LNG Participants will jointly evaluate the appropriate means for addressing any potential Jones Act concerns.

Should a prospective shipper of Alaska gas be interested in accessing North American gas markets, the Port Authority would work under its Teaming Agreement with BGT and its parent company MOL, to provide a cost-effective marine transportation solution in compliance with the Jones Act. BGT currently controls a fleet of eight U.S.-built LNG tankers that, following reflagging, would be available to serve gas transportation to domestic markets.

2.2.3.14(g) Destination Markets for LNG and NGL

The principal target markets for the Project's LNG and NGL are the Pacific Rim markets, specifically the major LNG consuming countries of Japan, South Korea and Taiwan. As described in Section 2.10.1.1, it is expected that the Project, as currently envisioned, would provide an attractive economic proposition to ANS gas producers participating in the open season, due to the premium pricing available in these markets.

A detailed discussion of the economic basis for the selection of East Asia as the targeted destination markets for LNG and LPGs is provided in Section 2.10.1.1.

While East Asian constitutes the principal target gas market at this time, the Port Authority has structured the Project in manner to facilitate access to U.S. and other North American gas markets as well. The Project's increased pipeline diameter from Prudhoe Bay to Delta Junction is sufficient to be considered as the "pre-build" of the first 550 miles of the proposed Alaska-Canada Highway project.

Additionally, the Port Authority is a participant in the open season being held by Sempra LNG for the expansion of the soon to be completed Energia Costa Azul regasification terminal in Mexico, just south of San Diego, California. This facility is at present the only receiving terminal on the West Coast of North America. The Port Authority has also received a letter of support from the only other fully permitted West Coast LNG receiving terminal, located in Kitimat, British Columbia, which would provide access to gas markets on the West Coast or in the Midwest via existing Canadian pipeline infrastructure.

Should a prospective shipper of Alaska gas be interested in accessing North American gas markets through either of these West Coast terminals, the Port Authority would work under its Teaming Agreement with BGT and its parent company MOL, to provide a cost effective marine transportation solution in compliance with the Jones Act. BGT currently controls a fleet of eight U.S. built LNG tankers that, following reflagging, would be available to serve gas transportation to domestic markets.

2.2.3.14(h) Regasification Infrastructure in the Primary Target Markets

This section provides a description of the regasification infrastructure in the targeted markets, as required under section 2.2.3.14 of the RFA.

Under the traditional LNG sales arrangements in the East Asian LNG markets, LNG is sold on a DES basis. As the buyer takes ownership of the LNG after unloading from the LNG vessel, the buyer is responsible for the provision of regasification, transportation and marketing once the LNG is sold on a "landed" basis. The seller, therefore, neither pays the cost, nor assumes the risk of regasification and downstream marketing. These customary arrangements differ significantly from those in North America, where the seller of LNG typically has to ensure that regasification and takeaway pipeline capacity has been secured.

Furthermore, regasification capacity in the East Asian LNG importing countries is ample and available in numerous terminals, with significant under-utilized spare capacities. Table 5 below shows the existing and planned regasification capacity in Japan, South Korea, and Taiwan. Based on 2006 LNG imports into Japan of approximately 60 mmta,[8] Japan alone has spare regasification capacity of approximately 130 mmta, or 68 percent.

Table 5 Regasification Capacity in Japan, South Korea and Taiwan

Name	Investor	Capacity (mmta)	Storage (1,000kl)	Start-up
Japan (existing):				
Sendai	Sendai City Gas	8.0	80	1997
Higashi Niigata	Nihonkai LNG	17.1	720	1984
Futtsu	Tokyo Electric	16.0	1,110	1985
Sodegaura	Tokyo Electric, Tokyo Gas	27.7	2,660	1973
Higashi Ogishima	Tokyo Electric	14.7	540	1984
Ogishima	Tokyo Gas	5.1	600	1998
Negishi	Tokyo Electric, Tokyo Gas	13.6	1,180	1969
Sodeshi	Shimizu LNG	6.4	177	1996
Chita Kyodo	Chubu Electric, Toho Gas	8.0	300	1977
Chita	Chita LNG	12.0	640	1983
Chita Midorihama	Toho Gas	0.8*	200	2001
Yokkaichi LNG Center	Chubu Electric	8.8	320	1987
Yokkaichi	Toho Gas	0.6	160	1991
Kawagoe	Chubu Electric	7.7	480	1997
Senboku 1	Osaka Gas	2.5	180	1972
Senboku 2	Osaka Gas	13.1	1,585	1977
Sakai	Sakai LNG	2.7	420	2006
Himeji Joint	Osaka Gas, Kansai Electric	4.0	1,440	1984
Himeji LNG	Osaka Gas	8.3	520	1979
Mizushima	Chugoku Electric, Nippon Oil	0.8*	160	2006
Hatsukaichi	Hiroshima Gas	0.4	170	1996
Yanai	Chugoku Electric	2.4	480	1990
Oita	Oita LNG	5.1	460	1990

[8] BP Statistical Review of World Energy June 2007.

Name	Investor	Capacity (mmta)	Storage (1,000kl)	Start-up
Tobata	Kitakyushu LNG	6.4	480	1977
Fukuoka	Saibu Gas	0.6	70	1993
Nagasaki	Saibu Gas	0.11*	35	2003
Kagoshima	Nihon Gas	0.1	86	1996
Japan (existing):		**193.0**	**14,553**	
Japan (planned):*				
Wakayama	Kansai Electric	N.A.	N.A.	N.A.
Joetsu	Chubu Electric, Tohuku Electric	N.A.	N.A.	N.A.
Omaezaki	Chubu Gas, Tokai Gas, Suzuyo	N.A.	N.A.	2010
Sakaide	Shikoku Electric	0.40	N.A.	2010
Kumamoto	Saibu Gas	N.A.	N.A.	N.A.
Nakagusuku	Okinawa Electric	0.70	N.A.	2010
Japan (planned):		**1.1**	**N.A.**	
Japan (existing + planned):		**194.1**	**14,553**	
S. Korea (existing):				
Pyeongtaek	KOGAS	13.3	1,000	1986
Inchon	KOGAS	22.4	2,480	1996
Tongyoung	KOGAS	5.0	980	2002
Gwangyang	POSCO	1.7*	200	2005
South Korea (existing):		**19.1**	**4,660**	
South Korea (planned):*				
Gunsan	GS Caltex	1.5	N.A.	N.A.
Cheju	KOGAS	N.A.	N.A.	2012
(4th Terminal)	KOGAS	N.A.	N.A.	2013
(5th Terminal)	KOGAS	N.A.	N.A.	N.A.
South Korea (planned):		**1.5**	N.A.	
South Korea (existing + planned):		**20.6**	**4,660**	
Taiwan (existing):				
Yungan	CPC	7.5	690	1990
Taiwan (existing):		**7.5**	**690**	
Taiwan (planned):*				
Taichung	CPC	1.7	N.A.	2007
Taiwan (planned):		**1.7**	N.A.	
Taiwan (existing + planned):		**9.2**		
Total Japan, S. Korea, and Taiwan (existing + planned):		**223.9**	**19,903**	

Sources: EIA, The Global Liquefied Natural Gas Market: Status and Outlook 2003, except where marked with an asterisk.
** The Institute of Energy Economics, Japan. "Natural Gas and LNG Supply/Demand Trends in Asia Pacific and Atlantic Markets (2006), September 2007.*

Export permitting for LNG exported from the Project is discussed in detail in Section 2.2.4.1.

2.2.3.15 Plan for NGL Processing and NGL Markets

As discussed in Section 2.1.4 above, propane and butane from gas transported to Valdez for liquefaction will be extracted at the fractionation facilities which will be an integral part of the LNG Facilities. There will be no separate NGL processing charge for LPG extraction, and terms and conditions of service will be governed by the commercial arrangements with respect to liquefaction, as described in Section 2.2.3.14 above.

As the production of LPGs at the LNG Facilities will be a by-product of LNG production, the commercial arrangements for LPGs will parallel those for LNG. As in the case of LNG marketing, LPGs will be marketed either by one or more of the LNG Project participants, or by ANS gas producers who wish to maintain control over the marketing function of gas and LPGs, as described for the case of LNG in Section 2.2.3.14 above.

As described in Section 2.2.3.14 above, the Port Authority is in discussions with several companies with significant industry experience regarding their potential role in the as LNG Participants. These companies have also expressed a strong interest in participating in the marketing functions for LPGs.

For a description of the economic basis for the targeted markets for propane and butane, please refer to Section 2.10.1.1(f).

2.2.4 Regulatory Plan

2.2.4.1 Regulatory Approvals

A detailed regulatory plan has been prepared for the project and is attached as Appendix OO ("**Regulatory Plan**"). Such plan discusses the key approvals, authorizations and permits necessary for the Project, including those available through an exercise of the YPC option by the Port Authority. However, the Regulatory Plan has been prepared without taking into account the potential Project schedule benefits arising from utilizing the YPC option to access existing regulatory approvals and data. Any time savings resulting from the utilization of existing YPC permits and data will provide an improvement above the base timeline and regulatory approach for the Project presented in the Regulatory Plan.

2.2.4.2 Rights-of-Way

Through the YPC option agreement, the Project will have access to the Federal Right-of-Way Grant issued to YPC on October 17, 1988 and State of Alaska Conditional Right of Way Lease issued to YPC effective December 10, 1988. Copies of these documents are discussed in the Regulatory Plan and attached in Appendices G-6 and G-7, respectively. The remainder of this Section provides a discussion of the right-of-way (**"ROW"**) plan assuming no benefits from the YPC option (i.e., the process must be started from scratch).

The Pipeline ROW consists of approximately 47% federal, 44% state, and 10% and private land. The detail of the process to obtain ROW on federal and state land is highlighted in Section 2.2.4 "Regulatory Plan." The details outlined below refer to the general process that will be implemented to obtain ROW that is not obtained through the Regulatory Plan.

It is anticipated that the Project will require preparation of an Environmental Impact Statement under the National Environmental Policy Act (**"NEPA"**), which will require public meetings held along the route of the project where land owners can obtain additional information about the project in a public forum. These public meetings are well advertised and offer the public and land owners a chance to learn and ask questions about the project. The first of these will likely be the open houses in local communities, held in fall of 2008.

2.2.4.2(a) Developing a Procedure

When preparing to acquire ROWs, the initial course of action is to develop processes and procedures that will define how this activity will be undertaken. This procedure would identify responsibilities and authorities, outline forms to be used, records to be kept and the overall methodology of how this activity will proceed. This procedure would then be used as a guide for all land agents and land acquisitions that occur during the project development. All land management personnel will be oriented to this procedure before commencing work. Good landowner relationships begin with the initial contact with the landowner and are very important to the Port Authority. Although what is outlined below is not a completed ROW procedure, it should indicate the general intent of how the ROW will be acquired.

It is expected that ROW for the Canadian segment of a future pipeline along the Alaska Highway route would be addressed by others when that project is being developed.

2.2.4.2(b) Establishing Field Offices and Pulling Ownership Records

The size of the organization required to negotiating ROW will be assessed during the early part of the development phase of the project. This will take into consideration the number of landowners and tenants, the required timescale within which the ROW has to be obtained, requirements for survey access, the complexity of the legal process and the need to establish a long term relationship with the landowners.

This particular project involves a significant amount of Federal, State and Alaska Native owned lands which have well defined acquisition processes that will be followed, however typically field offices are established in locations that offer access to the majority of the privately held land parcels.

The Project engineering team will provide the ROW Agents with preliminary Pipeline route maps at a scale and format sufficient to allow the Agent to identify the individual land tract holdings and owners potentially affected by the pipeline route, access requirements to the route and temporary work/camp sites. Once a general route has been established by the engineers, ROW Agents are dispatched to the Recorder's Office to pull tax records and title documents to verify ownership of land parcels that may be affected by the Project. Typically more title information is obtained that may be needed to insure that all land owners in the vicinity of the project can be notified if needed. Many times access, environmental and archeological surveys, or route changes alter who may be affected by the project and therefore to prevent multiple trips to obtain records, more information is pulled on the initial records effort than may ultimately be needed for the project.

2.2.4.2(c) Obtaining Survey Permission

For State, Federal and Alaska Native land, existing processes will be used to obtain survey permissions. For privately held land a project notification letter will be mailed to all landowners whose property the pipeline is deemed to cross or who may be affected by survey activity. This letter will also identify the types of surveys that might occur on their land and how those surveys are conducted. A key aspect of the route survey is to confirm and/or amend the preliminary Pipeline route to a level of detail sufficient for ROW negotiation and detailed engineering purposes. A Survey Permit Form will accompany the letter requesting the landowner to sign and return. Agents will allow ample time, subsequent to the mailing of the letter, before making personal contact with landowners. Non-resident and out-of-state contacts will be made in writing with follow-up telephone calls. In certain cases where a landowner is only willing to give verbal survey permission, the verbal permission may be accepted with a confirming letter sent to the landowner outlining the dialog of the verbal approval. Agent contact reports will be completed and filed daily outlining landowner contact information. Landowner call-ins will be documented by the recipient of the call with a follow-up agent contact report outlining the conversation. Signed permission letters will be filed in the land tract files.

A copy of the signed permit form, letter to landowner or agent contact report indicating approval to survey will be provided daily to the data specialist. The Project land record database will be capable of compiling lists of the names, addresses and telephone numbers of any landowners that have refused to sign the survey permit form as well as landowners that have signed the permit form. Additionally, the database will compile lists of landowners that request to accompany the surveyors on initial or future civil or environmental and cultural surveys or have other conditions and restrictions. This information shall be distributed to project personnel via a document titled an Ownership Line List which is the overall control document of the land acquisition process.

A survey permit will also be obtained from all landowners along non-public access roads required for construction, roads required to conduct geotechnical surveys, and re-routes. Survey permits will be obtained for all pipe storage and construction warehouse sites.

Agent Contact Reports will be completed daily and submitted to the field office for use and filing during the project. The Port Authority makes it a priority to not access private land until survey permission has been granted either through negotiation or legal process.

After the preliminary pipeline route has been surveyed, the following can be identified and marked on the route plans:

- width of the permanent ROW required to maintain and operate the Pipeline;
- additional temporary working width required to construct the Pipeline;
- any additional permanent and temporary access routes to the ROW from public highways;
- additional working areas required temporarily for the installation of specific crossings; and
- areas of land that will be required to be purchased/leased for permanent installations.

2.2.4.2(d) Right-of-Way Agent Supports Other Surveys

ROW Agents will be required to support civil surveys, environmental and cultural surveys, access road usage surveys, river reconnaissance surveys, line change surveys, geotechnical surveys or any other activity being performed in the field.

ROW Agents will meet daily with the environmental and cultural survey team leaders and civil survey party chief. All parties will be provided a current ownership line list and a copy of the written survey permit prior to starting the walk-through activities for that day. The Ownership Line List update shall be provided daily. The following shall be reviewed at these meetings:

- parcels that have been cleared;
- parcels that have been denied;
- new and existing conditions and restrictions;
- survey completed; and
- next day area to survey.

These meetings are mandatory and preferably will be held in person or by telephone. Any exception must have the Field Manager and Right-of-Way Manager's approval.

2.2.4.2(e) How Typical ROW Files are Maintained

Under no circumstances will permanent office files be removed from the field office. Permanent files will be copied for field file use as required. "Out-Cards" are required for files leaving the designated file room. Project office files shall include the following data:

- general and miscellaneous correspondence - bottom to top (reverse chronological order)
- maps and drawings not an exhibit to a document in a manila folder
- copy of title plat or tax card (if available) with tract highlighted in yellow
- LTC and related documents

- correspondence and agent contact reports
- agents contact report
- recorded Right-of-Way Easement with copy of check attached
- all documents signed by landowners/tenants and any orders of the court
- survey permit
- tenant's consent
- tract calculation sheet
- pre-construction damage release
- construction work space permit (if required)
- damage release (after construction) with copy of check attached

2.2.4.2(f) Handling of Encroachments and Crossings

For alignment segments paralleling an existing third-party pipeline or linear easement, the Port Authority will contact the third party and request a Letter of No Objection. For utility crossings typically the parties can exercise a Crossing Agreement or follow well established existing standards for utility crossings. The Port Authority anticipates close coordination with the TAPS operators during all stages of design and field activities.

2.2.4.2(g) Obtaining Non-Environmental Permits

The Permit Coordinator will secure all Non-Environmental Permits (permits not secured by the NEPA process). This person will collect permit applications, complete the application, attach relevant drawings and submit to Agency. The application will be submitted far enough in advance to receive an approved permit in advance of construction and to assure permit will not expire during the course of construction. Permits anticipated to be acquired by are:

- survey permit
- geotechnical drilling sites
- borough roads
- state roads
- township roads
- foreign line crossings (exclusive rights only)
- drains
- irrigation canals
- irrigation ditches
- flood plains
- railroads
- special use permits

- zoning permits
- building permits

2.2.4.2(h) Abstracting Procedure

An accurate legal ownership on all properties crossed by the proposed pipeline and occupied by facilities shall be researched and verified by the Title Supervisor prior to securing any permanent or temporary land rights. Great effort will be exercised to ensure the correct owner(s) of the land tract are identified and that such agreements are attached to the land and recorded at the Recorders Office

Record Search

- Title research will include searching back 40 years or to the last Warranty Deed of record, whichever comes first. Copies will be obtained and included in the acquisition file.
- On condemnation tracts, further title work will include identification of all liens and encumbrances such as mortgages.

Guidelines for Non-Fee Title Search

A chain of title will be prepared to determine current ownership. The following will apply:

- Type or print legibly.
- arrange title search files in the following order:
  - Limited Title Certificate (LTC);
  - Title Plat Map or copy of tax map (with parcel highlighted in yellow); and
  - Tax Card.
- Organize documents in reverse chronological order (the most recent document should be the first document listed on the LTC).
- If a new tract has been established by means of a property split, provide a separation LTC, drawing, copy of property tax identification, and a copy of all documents in reverse chronological order. Indicate on the LTC a proposed tract number and the tract number that the split tract originated from.
- Ownership of State, Borough and Town roads at the point of the pipeline crossing will be verified with the governing agency.
- If the current landowners own adjoining properties which the pipeline also crosses, acquired through the same chain of title, it shall be included on the LTC. If acquired by different chain of title, provide separate LTC and supporting documentation.
- Mortgages, leases and liens shall not be copied or researched unless obvious discrepancies or other issues of concern are discovered. Vesting deeds/current owner deeds will be copied. Book and page number on the LTC will list other deeds. The Title Coordinator will determine what other documents need to be copied.

- No subordinations will be acquired.
- All attachments or documents must be legible or marked "Best Copy Available."
- During the acquisition phase of the project, if it is discovered that a property has been affected by the death of a landowner, all efforts to acquire a "Certificate of Death" at the Recorder's Office or other source of Public Records will be made prior to requesting one from the other affected landowner.

Title Review

- All field files that are submitted for review will be turned in directly to the Title Coordinator.
- Files are subject to be returned to ROW agents during the review processes for any discrepancies that may occur.
- Files returned to agents will be accompanied by a "Title Review" form specifying the discrepancy.
- Title Search will be considered completed when the title package and title checklist has been assembled with all required records, all reviews complete, and approved by the Title Coordinator.
- Vesting Deeds, plats (if available) and copy of tax map with parcel highlighted in yellow, shall be issued to the Contractor's Drafting Department when there are any change in ownership or route.

Curing Title Defects

Title defects will be field reviewed and reported. A decision will be made by the Port Authority regarding those steps, if any that are necessary to cure the title. Title defects will be reported on a monthly report (spreadsheet) identifying tract, landowner, and issues related to defects and actions taken to remedy.

Record Retention

A Certified Abstract of Title Fee for Properties along with all other correspondence and/or documentation will be retained by the project and by its corporate successors.

Railroad Permits

A title search will not be necessary to determine whether the railroad owns in fee or through an easement. The fee owner should be established if believed to be different than the railroad.

Road Grants

When buying rights to a non-public existing access road or to establish an access road, a record search should be conducted, tracing back to a Warranty Deed.

Property Purchase in Fee

Certain properties may be obtained in Fee if required by the project.

Definitions

- Abstract of Title: A document containing a condensed history of the deeds, devises liens, judgments and other encumbrances affecting the title to land.
- Warranty Deed: Conveys title from the grantor to the grantee with a warranty of title. There are two types, General and Special. If a Special Warranty Deed is found in the Chain of Title it may be necessary to search further back to a General Warranty Deed.
- Quitclaim Deed: A deed operating as a release; intended to pass any title, interest, or claim with the grantor may have in the property, but not containing any warranty of a valid interest or title in the grantor.
- Special Warranty Deed: A deed that transfers ownership of a property and warrants that the property is free and clear from any liens and encumbrances, and the grantor will defend title against any defects, which occurred only during the time which the immediate grantor owner the property.
- General Warranty Deed: A deed that transfers ownership of a property and warrants that the property is free and clear from any liens and encumbrances, and the grantor will defend title against any defects that are discovered.

2.2.4.2(i) Drawings Required for Land Acquisition

Drawing Definitions:

- Sketch: A generic graphic representation of the pipeline on the land. No hard data points, just graphical representation of objects and their general location relative to others. Often used with an underlying topographic map.
- Exhibit: A drawing with hard data points, section corner(s), known established survey marker or established hard data point, centerline legal description or closed survey notes.
- Plat: A drawing with hard data points, section corner(s), known established survey marker or established hard data point, centerline legal description or closed survey notes and signed by a registered land surveyor.

Private Lands

- Pipeline easement

  A sketch is acceptable for general right-of-way purposes and negotiations where a general description is appropriate and no survey is performed.

  When survey is performed, an initial exhibit showing route and length of line in rods (for purposes of negotiating easement and payment) should be prepared. Exhibits or plats may be required per state statutes.

- Compressor station (fee purchase)

  These sites will require a plat.

State Lands

Maps, plats, and alignment sheets will be prepared according to the requirements of the ADNR-SPCO. (When an initial survey of the centerline is performed, surveyor should take into account the need for a final plat and collect appropriate data and tie to a section corner to help minimize overall project survey work.) The process for obtaining ADNR rights-of-way is described in the Regulatory Plan, Section 2.2.4 of this Application.

Federal Lands

Maps, plats, and alignment sheets will be prepared according to the requirements of the BLM Authorized Officer. (When an initial survey of the centerline is performed, surveyor should take into account the need for a final plat and collect appropriate data and tie to a section corner to help minimize overall project survey work.) The process for obtaining Federal rights-of-way is described in the Regulatory Plan, Section 2.2.4 of this Application.

State Highway Crossings

All crossings will be in compliance with the requirements of the Alaska Department of Transportation and Public Facilities ("**ADOT/PF**"). If a cased crossing is identified, Project approval must be obtained. A standard sketch or typical drawing is acceptable for filing. An as-built profile exhibit is required post-construction reflecting depth and location. (When an initial survey of the centerline is performed, surveyor should take into account the need for a final exhibit and obtain sufficient data to tie-in existing section corners and to minimize overall project survey work.)

Borough Road Crossings

All crossings will be in compliance with the requirements of the appropriate Borough. If a cased crossing is identified, Project approval must be obtained. A standard sketch or typical drawing is acceptable for filing, followed by an as-built profile exhibit post-construction that reflects depth and location. (When an initial survey of the centerline is performed, surveyor should take into account the need for a final exhibit and obtain profile readings and sufficient data to tie-in existing section corners and to minimize overall project survey work.)

Railroad Crossings

All crossings will be in compliance with the requirements of the permitting agency of the Alaska Railroad. If a cased crossing is identified, Project approval must be obtained. A standard sketch or typical drawing is acceptable for filing, followed by an as-built profile exhibit post-construction that reflects depth and location. (When an initial survey of the centerline is performed, surveyor should take into account the need for a final exhibit and obtain profile readings and sufficient data to tie-in existing section corners and to minimize overall project survey work.)

River/Stream Crossings

Construction requirements will be regulated by multiple state and federal agencies. All crossings must be permitted and all will require site-specific drawings delineating where and how the crossings will be made. (When an initial survey of the centerline is performed, surveyor should take into account the need for a final exhibit and obtain profile readings and sufficient data to tie-in existing section corners and to minimize overall project survey work.)

2.2.4.2(j) Determining Land Values / Basis of Compensation

A Market Study of Land Values might be performed by research of Recorder's Office records and consultation with real estate companies. A certified appraisal company may be used from time to time to establish fair market land values along the pipeline route when the above resources are not available. Prior to acquisition, a summary of land values per Borough will be prepared in a spreadsheet format for a guideline in establishing fair market values.

Permanent Easement Taking

Definition: The width of the easement after construction is completed.

Temporary Easements

Definition: Workspace outside the Permanent Easement taking and any additional Temporary Work Space (ATWS) used only for construction purposes at roads, rivers, stream crossings and environmental areas.

Access Roads

Definition: An access road is generally 60 feet wide and provides a needed way to travel to a construction site.

Damages

Crop damages will be based on United States Department of Agriculture estimates of crop yields and values or other defined statistics as available. Once crop types and values are determined, damages should be paid for the full amount before construction commences. Other post construction damages will be settled at the end of the project and should be minimal.

Damages will be paid to the landowner unless otherwise directed in writing by the landowner. The exception will be if a tenant has signed a lease agreement identifying the direction of damage payments.

Pipe Yards

Definition: A separate area off the pipeline right-of-way needed for pipe and material storage. These areas may be used for staging areas during construction.

The sites can be leased at locations to be determined and negotiated on a case-by-case basis. Length of lease shall be determined by project schedule.

Launcher/Receiver and Valve Setting Sites

These sites are normally located within the pipeline right-of-way already encumbered by the easement. These sites will be above-ground and will limit the landowner's use of his property in these areas. The location and size of these proposed sites will be established by Engineering.

Cathodic Protection Connector Line

Definition: Right-of-way needed for steel cable connecting pipeline to a ground bed at an area off the pipeline right-of-way to minimize corrosion of the pipe.

The length of the line and the size of the anode bed will be determined by engineering.

Fee Land Purchases

Fee land purchases may include radio tower sites, compressor stations, launcher/receivers and valve sites.

2.2.4.2(k) Acquisition of ROW

Acquisition of right-of-way, staging areas, pipe yards, access roads, warehouse facilities, and fee lands will be acquired timely and in sequence with project schedule.

Execution of Agreements

The requirements and conditions for the acquisition ROW agent to perform their duties of securing signed easements are as follows:

The Agent should verify all documents are executed with the same name that appears on the document. If the landowner is a corporation, corporate resolutions may be required from the corporation. Documents shall be executed in accordance with state laws and regulations.

The Agents will secure the landowner's signature on three originals of the easement. One copy of the fully executed document should be provided to the landowner and two fully executed easements should be forwarded to the Document Coordinator.

Notary Public acknowledgements to signatures will be in accordance with applicable state laws in the state in which said document is executed.

- As signed documents are received by the Document Coordinator, a double check policy shall be in effect to verify that each document is properly completed.
- Upon approval by the Documents Coordinator, the document will be sent by certified mail, return receipt requested, within a reasonable period of time to be recorded in the appropriate Borough or state records.
- Right-of-Way Agreements shall be pre-numbered using permanent tract numbers numbering system.

2.2.4.2(l) Construction and Cleanup

Agents will be available during construction and restoration to serve as liaison between the landowner and construction contractors in their respective areas to ensure all agreed to construction conditions are met. Notification to landowners shall be made prior to construction commencement.

Agents will report all discrepancies, omissions or deficiencies relevant to land and right-of-way matters to the designated construction authority.

Agent will be responsible for acquiring "Landowner Approval of Cleanup" in writing. The construction contractor shall be required to co-sign the approval of clean-up document. This activity shall immediately follow cleanup operations.

2.2.4.2(m) Other Forms and Procedures to be Developed

- Survey Permit Ownership Line List
- Ownership Line List (Along the Route)
- Ownership Line List (Along Access Roads)
- Ownership Line List (Storage Yards)
- Ownership Line List (Abutting Utilities)
- Ownership Line List (Abutting Station Sites)
- Title Run Sheet
- Limited Title Certificate (LTC)
- Title Review Form
- Field Personnel Conduct
- Survey Permit Form
- Contact Report
- Good Landowner Communication
- Check Writing Procedure

2.2.4.3 Commitments for FERC-Certificated Project

The Port Authority anticipates the Project will be subject to the jurisdiction of FERC, meaning the Project will be a FERC -Certificated Project. This includes complying with all other aspects of the FERC review process and the AGIA process that are associated with this permitting course of action.

Pursuant to the requirements applicable to a FERC-Certified Project under AS 43.90.130(3), the Port Authority makes the following commitments:

1. The Port Authority commits to conclude a binding open season that is consistent with the 18 CRF, Part 157, Subchapter B and 18 CFR Sections 157.30-157.39 by

March 31, 2011, or 36 months following the anticipated conclusion of the AGIA licensing process.

2. The Port Authority commits to apply for FERC approval to use the pre-filing procedures set out in 18 CFR Section 157.21 and to submit its pre-filing application by July 25, 2009.

3. The Port Authority commits to apply for a FERC Certificate of Public Convenience and Necessity to authorize the construction and operation of the Project, and to file such application with FERC by November 30, 2010.

Section 2.2 (Development Plan) of this Application describes the numerous planning, permitting, and engineering design activities to be undertaken to achieve these milestones. Section 2.2.4 (Regulatory Plan) of the Application provides a regulatory schedule reflecting the above milestones for the pre-filing application to FERC and the submittal of the application for a FERC certificate.

2.2.4.4 Commitments for RCA-Certificated Project

The Port Authority anticipates that the Project will be a FERC-certificated Project. This includes complying with all other aspects of the FERC review process and the AGIA process that are associated with this permitting course of action. Thus the Port Authority need not make the commitments required under AS 43.90.130(4) for a project regulated by the Regulatory Commission of Alaska ("**RCA**").

The Port Authority commits to providing a minimum of five delivery points for in-State service of natural gas as per AS 43.90.130(12) and (13). It is the Port Authority's understanding that the in-State natural gas distribution systems, which are anticipated to be built and operated by other entities, such as ANGDA, will be under the regulatory jurisdiction of the RCA beginning at the point where they tie into the Project delivery points.

2.2.4.5 Commitments for a Canadian Pipeline Project

The Port Authority is not proposing a Canadian pipeline project in this Application and, therefore, the provisions of this section of the RFA are not applicable. For a discussion of the Port Authority's expectation regarding the future development of a Canadian pipeline project and its interaction with the proposed All-Alaska Gasline, please refer to Section 2.2.3.13 above.

2.2.5 Local Project Headquarters Plan

In accordance with AS 43.90.130(14) the Port Authority commits to establish a local headquarters in Alaska for the Project.

The Port Authority believes it is important that the Project headquarters be located in a municipality through which the pipeline traverses and Fairbanks, located midway along the pipeline route, is logistically the ideal location.

The Port Authority already has its main office located in Fairbanks and, upon issuance of the License, will expand the Project headquarters in Fairbanks to accommodate the future needs of all phases of the project.

Potential Project contractors, such as Bechtel, may establish their respective in-State Project headquarters elsewhere.

2.3 Execution Plan

2.3.1 Project Execution Plan

A detailed Project Execution Plan has been developed for the Project by Bechtel. It is attached as Appendix PP to this Application.

An Environmental Management Plan for the Project been prepared by ENSR, which accompanies the Project Execution Plan, is attached as Appendix QQ to this Application.

2.3.2 Managing Capital Costs

Managing capital cost on a development of this magnitude is a significant challenge, which requires careful planning, monitoring and control by a Project management team with solid expertise from a world-class contractor. The Port Authority's relationship with Bechtel enables the Project to benefit from that company's outstanding project management experience.

A detailed description of Bechtel's approach in philosophy, systems and organizational structure is reflected in the Project Execution Plan attached as Appendix PP herein. Information on Bechtel's track record and capability to operate within a cost estimate is provided in Section 2.9.

2.3.3 Project Labor Agreement

The Port Authority is pleased to commit to a Project Labor Agreement. The Port Authority and appropriate labor representatives have committed, by a signed Letter of Intent, attached as Appendix MM, as follows:

- Use of modernized technology with proven results of quality and integrity to increase productivity and efficiency.
- Incorporation of "pre-job" meetings where all aspects of a particular work process are explained and jurisdictional assignments are made; thus lessening the opportunity for workplace disruptions due to mis-assignments.
- Bright lines established for work done under the auspices of the building trades and work under the auspices of the pipeline crafts.
- Use of composite crews where appropriate.
- Development of a formula to assure that wage and benefits and other economic factors are known for the duration of the project.

- *Incorporation of methods for complying with Sections 28 & 29 of the Right of Way* Statutes which govern the authority to operate within the ROW. Including incorporation of language included in the current Labor Agreement with the Alyeska Pipeline Service Company maintenance and construction contractors which has been highly successful in providing career opportunities to Alaskan Natives.
- While the Letter of Intent identifies the intention of the parties to utilize the original TAPS Project Labor Agreement as a template; the parties recognize that the following areas either were originally not recognized or were recognized but not deemed important. The Port Authority intends to craft language to:
  - allow pre-employment drug and alcohol testing;
  - treat safety as a number one priority;
  - allow for background checks;
  - deal with HIRD issues (harassment, intimidation, retaliation, and discrimination); and
  - maximum use of hiring hall procedures to assure that qualified Alaska/local hire is accomplished to the fullest extent possible under law.

2.3.4 Alaska Hire

AS 43.90.130(15)(A) requires a commitment to "hire qualified residents from throughout the state for management, engineering, construction, operations, maintenance, and other positions on the proposed project." Under the terms of a negotiated Project Labor Agreement, the Port Authority commits to hiring qualified residents of the State of Alaska with a "state resident preference" for all available positions in the management, engineering, construction, operations, and maintenance phases of the project, to the greatest extent allowed by law.

AS 43.90.130(15)(B) requires a commitment to "contract with businesses located in the state." The Port Authority will advertise, procure and contract for project development, construction, operation and maintenance, with preference to qualified and capable businesses located in the state, to the greatest extent allowed by law.

AS 43.90.130(15)(C) requires a commitment to "establish hiring facilities or use existing hiring facilities in the state." Under the terms of a negotiated Project Labor Agreement, the Port Authority commits to utilizing existing hiring facilities within the state, and will establish additional hiring facilities within the "project headquarters" as necessary.

AS 43.90.130(15)(D) requires a commitment to "use, as far as is practicable, the job centers and associated services operated by the Department of Labor and Workforce Development and an Internet-based labor exchange system operated by the state." Under the terms of a negotiated Project Labor Agreement, in addition to the pipeline building trades training and hiring centers located within the state, the Port Authority shall use the job centers and associated Alaska Department of Labor and Workforce Development services, including the use of an internet-based labor exchange system operated by the state for the recruitment and hire of project personnel.

Licensee and appropriate labor representatives by attached signed Letter of Intent also commit to the following.

- Maximum use of hiring hall procedures to assure that qualified Alaska/local hire is accomplished to the fullest extent possible under law.
- Identifying organized Alaskan Contractors for contracts or subcontracts on this project by working with contractor associations such as the Alaskan—Associated General Contractors, National Electrical Contractors Association, & the National Mechanical Association.
- Continued use of hiring halls, both virtual and mortar/bricks, which currently cover the entire State of Alaska.
- Continued partnership with Alaska Works to identify and train journey and apprentice workers in rural and urban Alaska. Participation to as full extent as appropriate with AK DOL programs existing today and working with the Department in developing processes and programs in the future.
- Alaska hire to emphasize training the Alaskan workforce for the next generation. Recruitment, classroom training and on-the-job experience to take place for pre-construction infrastructure, construction undertaken by the licensee under AGIA, maintenance of operational structures and pipelines, and training for opportunities post construction not covered under this PLA. Recruitment to emphasize rural Alaskans, K-12 and post secondary schools and institutions. Additional emphasis on our helmets to hardhats program to develop construction career opportunities for returning veterans.

2.4 Operations Plan

2.4.1 Expansion

2.4.1.1 Market Assessment

Under the RFA, the Applicant for a License must detail how Applicant intends to comply with the requirements set forth below. The Port Authority hereby makes the commitments described below.

(1) *Applicant must commit that all nonbinding solicitations of interest conducted pursuant to the License and for the purposes of assessment of potential market demand for expansion capacity must:*

(a) Be conducted at least every two years after the conclusion of the first binding open season

Upon conclusion of the initial binding open season, the Port Authority commits to assess the market demand for additional pipeline capacity at intervals not to exceed two years. It is anticipated that such solicitations will be in the form of conducting non-binding open seasons (for delivery to destinations within and outside of the State) and/or conducting or adopting a study of gas consumption needs and prospective points of delivery within the State and rely upon such study to develop the contents for the open season for deliveries within the State. It is anticipated that the Port Authority, from time to time, may enter into pre-subscription agreements with anchor shippers regarding an expansion of the Pipeline. In this event, the Port Authority will offer the same terms and conditions to other prospective shippers in a subsequent binding open season that was afforded the anchor shipper(s).

(b) Be public and provide at least 30 days' prior public notice of each nonbinding solicitation of interest through methods reasonably calculated simultaneously to notify all interested parties, including postings on internet web sites, press releases and direct mail notification and other advertising

The Port Authority will post all materials associated with nonbinding open seasons on its company web site no less than 30 days prior to commencing any such open season. The Port Authority will also develop project specific websites that will be established when a project becomes further developed. The Port Authority will also announce any nonbinding open season through the form of a press release to be issued concurrently with the posting on the company web site. Immediately following any public announcement and posting, the Port Authority will directly contact any parties that the Port Authority deems may be interested in participating in the applicable expansion project.

(c) Set forth the next reasonable engineering increment of capacity, consistent with AS 43.90.130(6) (B)

All nonbinding solicitations of interest will detail the next reasonable engineering increment of capacity. As set forth in Section 2.4.1.2 below, it is anticipated that reasonable increments of capacity into the foreseeable future will be satisfied by the addition of compression facilities potentially coupled with new receipt and/or delivery facilities.

(d) Contain Licensee's good faith estimate of Recourse Rates for the next reasonable engineering increment of expansion capacity as well as a larger expansion utilizing Rolled-in Rates to the levels required by AS 43.90.130(7)

All nonbinding solicitations of interest will contain a good faith estimate of Recourse Rates for the next reasonable increment of expansion capacity.

Regarding larger expansions, the Port Authority will provide project descriptions (incremental billing determinants and incremental facilities) for projects that would meet both: 1) traditional rolled-in rate treatment (no increase in rates to existing shippers), and 2) rolled-in rate treatment utilizing the 15 percent threshold set forth in AS 43.90.130(7)(B).

(e) Set forth a good faith estimate of how long it will take to place into service the next reasonable engineering increment of capacity

The Port Authority commits to comply with this provision.

(f) *Contain provisions that permit Creditworthy prospective shippers to make binding commitments for expansion capacity in a binding open season to be conducted promptly by the Licensee subsequent to the nonbinding solicitation of interest*

Criteria will be established in materials provided in any nonbinding solicitation of interest that will facilitate the timely execution of contracts in a subsequent binding open season, including provisions for creditworthy prospective shippers to make binding commitments for expansion capacity.

(g) *Commit the Licensee to promptly and diligently pursue a binding open season for expansion capacity, conducted in a manner consistent with the requirements of 18 C.F.R S 157.30 – 157.39, to the extent that the expressions of interest demonstrate a market demand on commercially reasonable terms by Creditworthy shippers that equals or exceeds the next reasonable engineering increment of capacity, as defined in AS 43.90.130 (6) (B)*

To the extent that the expressions of interest for expansion capacity demonstrate a market demand on commercially reasonable terms by creditworthy shippers that equals or exceeds the next reasonable engineering increment of capacity, as defined in AS 43.90.130 (6) (B), the Port Authority will promptly and diligently pursue a binding open season for expansion capacity, conducted in a manner consistent with the requirements of 18 C.F.R S 157.30 – 157.39, as currently written.

(2) Applicant must commit that in a binding open season conducted after the nonbinding solicitation of interest it will not:

(a) *Require a prospective shipper to agree to any particular rate (other than the recourse rate), or*

The Port Authority commits to comply with this provision.

(b) *Require an existing shipper to pay any rate for a capacity expansion prior to the date the new expansion facilities go into service.*

The Port Authority commits to comply with this provision.

2.4.1.2 Expansion Terms

The initial design for the Pipeline allows for economic expansions of the system through the addition of compression facilities as opposed to the installation of additional pipeline facilities (looping). As previously mentioned in this Application, the Port Authority proposes to install adequate compression to transport the initial flow of 2.7 bcfd to Valdez. Three additional intermediate sites have been identified that will support the ultimate Pipeline capacity of approximately 6 bcfd at the inlet to the Pipeline, including possible future deliveries to the Canadian border. The proposed "expansion compressor units" are anticipated to be of comparable size as the compressor units that will be installed in the initial build.

It is anticipated that the cost of expanding the system transportation capability from 2.7 bcfd to 6 bcfd would qualify for rolled-in rate treatment, including fuel, when taking into account the additional expansion billing determinants as well as costs associated with a relatively inexpensive expansion through the addition of compression horsepower in addition to the installation of new pipeline facilities extending from Delta Junction to the Canadian border. It is expected that expansion(s) between the initial 2.7 bcfd and 6 bcfd will result in rate decrease(s) for initial shippers as well expansion opportunities for new shippers under commercially reasonable terms.

As required under AS 43.90.130(6) and RFA section 2.4.1.2, the Port Authority commits to expand the Project in reasonable engineering increments and on commercially reasonable terms that encourage exploration and development of gas resources in Alaska, with "commercially reasonable terms" and "reasonable engineering increments" having the meaning set forth in AS 43.90.130(6).

As also required under AS 43.90.130(6) and RFA section 2.4.1.2, the Port Authority further commits to promptly and diligently pursue all regulatory approvals upon the receipt of acceptable binding commitments for expansion capacity, and commit to promptly and diligently proceed to expand the Project at a reasonable engineering increment sufficient to satisfy all demand for expansion capacity so long as: (a) additional revenue, if any, from existing transportation contracts on the Project, plus the projected revenue from binding expansion capacity commitments, cover the costs of the expansion (including fuel costs and a reasonable return on capital as authorized by the RCA, as applicable); and (b) the Port Authority's ability to recover the costs of existing facilities is not impaired.

2.4.1.3 Rolled-in Rates Commitment

Consistent with AS 43.90.130(7) the Port Authority:

(A) will propose and support the recovery of mainline capacity expansion costs, including fuel costs, from all mainline system users through rolled-in rates as provided in (B) and (C) of this Section or through a combination of incremental and rolled-in rates as provided in (D) of this Section;

(B) will propose and support the recovery of mainline capacity expansion costs, including fuel costs, from all mainline system users through rolled-in rates if the rolled-in rates would increase the rates: (i) not described in (ii) of this subsection by not more than 15 percent above the initial maximum recourse rates for capacity acquired before commercial operations commence (in this sub-section, "initial maximum recourse rates" means the highest cost-based rates for any specific transportation service set by the RCA when the pipeline commences commercial operations); (ii) by not more than 15 percent above the negotiated rate for pipeline capacity on the date of commencement of commercial operations where the holder of the capacity is not an affiliate of the owner of the pipeline project (for the purposes of this sub-section, "negotiated rate" means the rate in a transportation service agreement that provides for a rate that varies from the otherwise applicable cost-based rate, or recourse rate, set out in a gas pipeline's tariff approved by the RCA); or (iii) for capacity acquired in an expansion after commercial operations commence, to a level that is not more than 115 percent of the volume-weighted average of all rates collected by the project owner for pipeline capacity on the date commercial operations commence;

(C) will, if recovery of mainline capacity expansion costs, including fuel costs, through rolled-in rate treatment would increase the rates for capacity described in (B) of this paragraph, propose and support the partial roll-in of mainline expansion costs, including fuel costs, to the extent that rates acquired before commercial operations commence do not exceed the levels described in (B) of this Section;

(D) may, for the recovery of mainline capacity expansion costs, including fuel costs, that, under rolled-in rate treatment, would result in rates that exceed the level in (B) of this Section, propose and support the recovery of those costs through any combination of incremental and rolled-in rates;

(E) will not enter into a negotiated rate agreement that would preclude the applicant from collecting from any shipper, including a shipper with a negotiated rate agreement, the rolled-in rates that are required to be proposed and supported by the applicant under (B) of this Section or the partial rolled-in rates that are required to be proposed and supported by the applicant under (C) of this Section.

2.4.1.4 General Expansion Provisions

The pledge to "promptly and diligently pursue" binding open seasons, regulatory approvals and expansions, as used in this subsection, means that the Port Authority shall act in a manner that is commercially reasonable in the interstate gas pipeline industry in the United States with respect to timing and execution of relevant actions. A shipper is deemed "creditworthy" if it satisfies the creditworthiness standards for the Project's applicable tariffs. For expressions of interest and expansions undertaken prior to regulatory approval of such standards, creditworthiness shall be determined according to the standards the Port Authority applies in its initial binding open season.

The Port Authority will file, as part of its tariff, its determination of the reasonable engineering increment of capacity based on the design of the Project prior to project sanction and each time the design capacity of the Project changes due to modifications of the facilities or operation of the pipeline (other than normal day-to-day changes in pipeline operations). For purposes of determining the reasonable engineering increment of capacity that can be added by the addition of pipe (commonly referred to as "looping"), the Port Authority shall base its calculations on: (1) the addition of a full valve section based on the original pipeline mainline valve locations; and (2) pipe diameter that would be required were a full loop of the pipeline to be undertaken.

2.4.2 Pipeline Operating and Maintenance Plan

The RFA does not specifically request an operating and maintenance ("**O&M**") plan for the Project. This section of the Application provides the outline of the O&M plan for the Pipeline (the "**Pipeline O&M Plan**") that will be developed for the Project. In this section, the Port Authority and its Project partners are referred to as the owner ("**Owner**").

2.4.2.1 Introduction and Objective

The objective of the Pipeline O&M Plan is:

- To demonstrate that the pipeline system complies with the requirements of all Federal, State and local requirements – both in design and operations.
- To demonstrate that the pipeline system will be operated within it's design parameters.
- To demonstrate the Owner's intent to have in place a fully effective asset integrity management system which will ensure the safe and reliable transport of gas.
- To ensure long term reliability of the pipeline system by minimizing risks and threats to the system and developing remedial actions to address those risks and threats in a safe, timely and cost effective manner.
- To demonstrate the Owner's intent to have in place a fully effective and acceptable emergency management system which will ensure that system emergencies are safely and effectively handled with minimum risk to the general public, environment and other adjacent utilities.
- To demonstrate the Owner's ability to supply all quantities of contracted gas within the agreed commercial terms.

Recognizing that there is no universal O&M plan that applies to all pipeline systems, although there are some common themes, the Owner will develop a system-specific Pipeline O&M Plan which will be fully activated some six months prior to the introduction of first gas into the system. This provides sufficient time to train and assess the competency of O&M personnel, and undertaken emergency response exercises to gauge the effectiveness of the plan.

The Pipeline O&M Plan will be developed after the design of the system is established and the layout and types of equipment to be utilized are known, so that the Pipeline O&M Plan encompasses how best to operate this system. The general content of the preliminary Pipeline O&M Plan is provided below.

2.4.2.2 Codes, Specifications and Regulations

The list bulleted below is not all encompassing, however listed below are some of the codes, specifications and regulations that will govern this system.

- American Gas Association (AGA)
- American Petroleum Institute (API)
- American National Standards Institute (ANSI)
- American Society of Mechanical Engineers (ASME)
- Instrument Society of America (ISA)
- National Association of Corrosion Engineers (NACE)
- National Fire Protection Association (NFPA)

- Institute of Electrical and Electronic Engineers (IEEE)
- American Concrete Institute (ACI)
- American Institute of Steel Construction (AISC)
- American Welding Society (AWS)
- American Gears Manufacturers Association (AGMA)
- American Society of Testing and Materials (ASTM)
- American Society of non-Destructive Testing
- Antifriction Bearing Manufacturers Association (AFBMA)
- Associated Factory Mutual Companies (FM)
- Crane Manufacturers Association of America (CMAA)
- Hydraulics Institute Standards for Centrifugal, Rotary and Reciprocating Pumps
- Manufacturers Standardization Society (MSS)
- National Electrical Manufacturers Association (NEMA)
- Steel Structure Painting Council (SSPC)
- Underwriters Laboratories INC (UL) (only for equipment)
- National Electrical Testing Association (NETA)
- Insulated Cable Engineers Association (ICEA)
- Uniform Building Code (UBC)
- American Association of State Highways Transportation Officials (AASHTO)
- Occupational Safety and Health Administration (OSHA)
- Department of Transportations (DOT)

Although there are specific specifications that can be called out for each bulleted item above in great length, an example of one standard that is typically used by cross country transmission pipelines is the DOT 49 CFR Part 192 Transportations of Natural and Other Gas by Pipeline: Minimum Federal Standards.

The Pipeline O&M Plan developed for the Project will outline the governing codes, specifications and regulations to be adhered to.

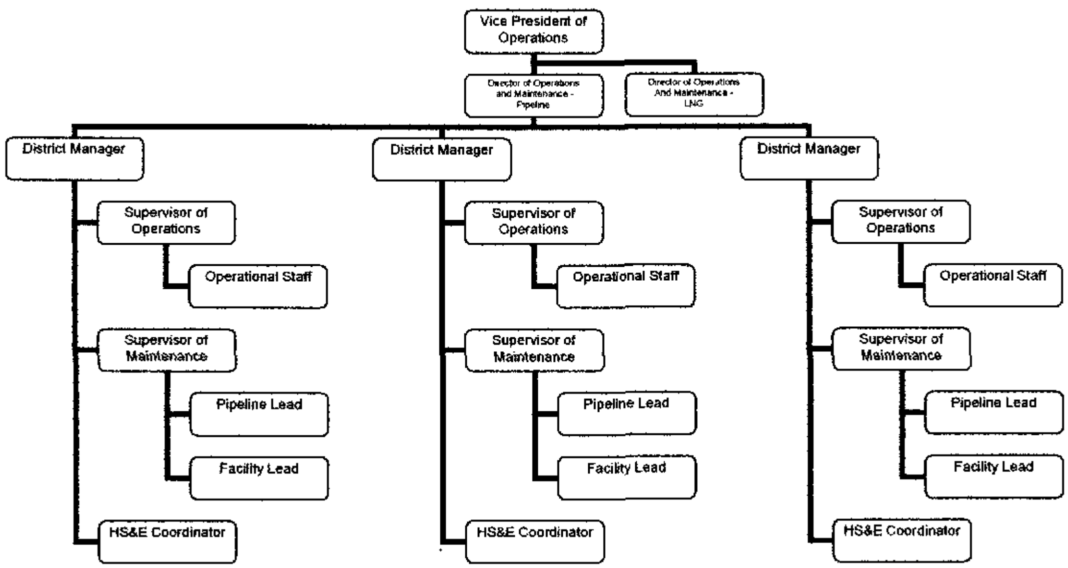
2.4.2.3 Management and Administration

The Pipeline O&M Plan will spell out how Owner's the O&M organization is to be developed. This will include the overarching structure that supports HS&E efforts; commercial operations, maintains drawings; manages new projects; technical experts (such as rotating equipment, measurement, pipeline, electrical and many other engineers) to provide support as well as many other persons all working to the common goal of operating a safe, reliable system.

2.4.2.4 O&M Organization

The Pipeline O&M Plan will detail the structure of the Owner's O&M organization. Below is a typical layout of a pipeline O&M staff. This is provided for illustrative purposes only. A full organization chart covering all components of the system will be developed during the execution phase of the project.

Figure 14 Indicative O&M Organizational Structure



Staffing these positions is a key to a successful operation and it is the intent of the Owner to seek to employ Alaskans in the vast majority of the positions. Employees will be trained, have ongoing skill assessment requirements and be expected to improve their skill sets in order to progress to higher level positions. Each year a personal plan will be developed for each employee and each employee evaluated at the end of the year against this plan. Competency enhancements will be achieved by an appropriate combination of education, training and practical experience.

The Pipeline O&M Plan will detail the roles and responsibilities of each employee. This will define what they are accountable for, responsible for and what role they play in various O&M activities.

2.4.2.5 Health, Safety and Environmental

An important part of any ongoing operations is to maintain constant monitoring and preparedness for any health, safety or environmental event that might occur. Some positions on the operations staff will be solely dedicated to HS&E efforts and HS&E will be championed by a senior member of the management team.

- Safety is the highest priority. There will be constant ongoing efforts to keep safe work habits and safe operational activities at the forefront of our work at all times. These will include tailgate meetings, periodic safety training (on driving habits, work processes, personal protection, etc), as well as awareness updates on emergency shutdown systems purposely put into the system during the design phase of the project.
- During operations the main priority is to prevent unplanned releases and to mitigate their effects if they occur. This will include preparing and implementing a plan for pollution prevention and spill response (e.g. spill prevention control and countermeasure plan). This is also planned into the design of the system by completing a thorough high consequence area ("**HCA**") study or class location assessment and modifying the system accordingly in the design phase of the project.
- Health quality is an ongoing effort as well. Employees will be offered tools and resources to maintain a healthy lifestyle. HS&E staff members will be trained in emergency first aid and will provide ongoing training to other employees as needed.

2.4.2.6 Operational Limits

The operational limits of the system are established by the engineering group during the development of the project. This is typically known as the basis of design and it outlines the limits of the designed capability of the system. This design information along with the construction and commissioning records of the system will be readily available to the O&M personnel in both 'soft' and 'hard' copy. Amendments to the system will be subject to the Owner's management of change procedure which will include a requirement to update all design and construction records.

Operators will be trained on the design limits and tasked with keeping the system within these limits. A significant amount of automation and control safeguards against exceeding these limits, however it is the O&M group that maintains these systems to ensure they are always working effectively.

2.4.2.7 Landowner and Stakeholder Communications

Anytime unique maintenance work or a special operational activity occurs on a land owner's property the Operations personnel will, as part of their work task planning, notify said land owner, or any other stakeholder that might be affected by such an operation or activity.

The Owner will participate in the "Dig Safe" or "One Call" program where landowners, as well as others working on that land, can request a marking of the underground utilities. In addition on an annual basis, public education material is created and distributed to all landowners as well as the general public about what to do in an emergency, the dangers of digging near underground pipelines and who to call if they spot a problem.

A key stakeholder during the operational phase of the project will be the Alyeska Pipeline Service Company ("**Alyeska**"). The Owner will seek to establish formal liaison/communications channels with it to facilitate and synergize operational activities.

2.4.2.8 Maintaining Operating Records

Operators of systems are required to keep on-going maintenance records. Not only is this required by law, these records are a very useful tool in preventative and predictive maintenance plans. For example every time a flow meter is serviced a record of that service is created showing when and what was done to that meter. The same principles apply to any piece of equipment on the system. In some instances monitoring these maintenance records will give an operator an indication a problem is arising long before a real problem occurs. For example, continued monitoring of vibration readings of rotating equipment can often help an operator predict when maintenance will be needed.

In addition to having maintenance records, the control center via the SCADA system will keep continuous records of multiple data points for long periods of times. These records are easily retrievable, stored in computer data storage devices and will be used to optimize the operation of the network and to analyze root causes of problems if they occur.

2.4.2.9 Emergency Procedures Manual

A key component of the Pipeline O&M Plan is dedicated to emergency response procedures ("**ERP**").

In addition to ensuring the operators employees are prepared and trained, it will also be a priority to ensure that local emergency responders are trained and have the equipment they need to assist in an emergency. As mentioned above, some positions on the operations staff will be solely dedicated to HS&E efforts and ensuring preparedness for emergencies falls under this job description.

Because ERP must be Project-specific, it will be developed during the development and execution phases of the Project. Key sections that would be addressed in the ERP are:

- emergency response plans for the system as well as each individual facility
- natural disaster preparedness
- homeland security training and preparedness
- incident management plans (incident command)
- incident reporting and investigation plan
- testing of emergency systems plan

The Pipeline O&M Plan will detail the frequency at which the ERP will be tested by both desk top and full scale simulation which will include the participation of local emergency responders as appropriate. Consideration will also be given to establishing a mutual aid protocol with Alyeska.

In addition the following systems and activities will be put in place to prevent the occurrence of a major accident:

- geographical information system

- integrity monitoring/pressure systems inspections
- condition monitoring/on-line inspections
- "dial before you dig" scheme
- aerial and walking surveys
- land owner liaison visits
- scheduled maintenance program
- 24-hour maintenance call out response
- 24-hour emergency response
- target response times
- identification of HCA zones
- new technology awareness

2.4.2.10 Risk/Threat Assessments and Mitigations

During the design phase of the project all risk/threats to the system will be identified and addressed through the application of HAZOP analyses at key points. In addition, all risk related scenarios will also be assessed during the development and execution phases of the Project through a Pipeline-specific safety evaluation and quantified risk assessment process which will include:

- hazard or threat identification
- potential for major accident
- consequences of pipeline failure
- risk assessment
- prevention and mitigation

The identified hazard events will be described together with the initial cause and consequences of that event. Also described will be the preventative and remedial measures that will be implemented and the resultant modified consequences as influenced by the control measures introduced in order to prevent a major accident. The process is designed to lower the risk to as low as is reasonable practicable.

Typically, some of the risk/threats that will be considered and mitigated will be:

- Third party damage:
    - Excavation by others: Of the relatively few pipeline incidents that do occur, the majority are caused by third parties hitting the pipeline. Thus, significant effort will be put into mitigating this risk by placing warning signs, educating the public on digging, designing and installing automatic shutdown equipment, erecting security fencing and cameras at above ground sites, area classifications and surveillance activities.

- Vandalism: Although typically random acts, automatic shutdown equipment, security fencing, surveillance and security cameras are the main mitigation measures.
- Unintended damage: Pipelines are surveyed on a routine bases by aerial patrols that look for any damage to the ROW, exposed pipe or third party encroachments to the pipeline.

- Upset conditions: This typically means that the facility is not operating within the operating limits. The control center via the SCADA system keeps continuous signals on a 24/7/365 monitored basis to allow the operators warning of these upset conditions. These systems will alarm the operators when the system is nearing the operational limits and if the operational limits are exceeded without operator actions the control system will begin an automatic, controlled shutdown, of the system to bring it back into operational parameters. These safeguards are designed into the system and maintained by the O&M group.
- Class location or HCA: For natural gas pipelines there are minimum standards for ensuring public safety. The 2002 Pipeline Safety Improvement Act and the subsequent DOT Part 192 Subpart O require a formal integrity management plan and mandatory integrity inspections of HCA's. As a general rule there are certain types of locations that, if an accident were to occur, would be more likely to cause harm (or consequences) to the environment or to the public. These threats/risks are mitigated by the class location system outlined in DOT 49 CFR Part 192. Design mitigation will include compliance with block valve spacing requirements, increases to the pipe wall thickness and the use of higher safety factors for locations such as water crossings, above ground facilities, populated areas, and road crossings.
- Corrosion: After third party damage, the next leading threat to pipeline systems is corrosion. To mitigate or significantly slow down corrosion, the first protective measure is the coating on the pipeline. During manufacturing and construction there are several inspection activities undertaken to ensure the coating is installed properly. After coating, the next protective measure is cathodic protection. This involves inducing a current into the pipeline with sacrificial anodes that direct the corrosion away from the pipeline. O&M procedures are a key to maintaining the functionality of this system. A third protective measure is internal inspection pigs (smart pigs). These are devices that locate areas of wall thickness loss and other defects in the pipeline that may be vulnerable to problems (a predictive maintenance tool) at some time in the future. These pigs will be run through the pipeline on a regular interval with the detailed data analyzed and compared with previous runs to establish an overall life of the pipeline system. Any identified critical defects will be repaired after a pig run and then per known standards, a life expectancy calculation will be done to determine when the next pig run is required. It is expected that the first smart pig run will occur within the first year after construction to establish a baseline of the pipeline and ensure no installation anomalies exist. This will then be used as a comparison against future pig runs.
- Ground movement: The pipeline and facilities will be designed appropriately for the identified earthquake zones. Designs exist that allow pipe to cross fault lines and flex to earth movements. Soil erosion is another ground movement category. To mitigate ground movements the pipeline will be surveyed on a routine bases by aerial patrols to locate any damage to the ROW, exposed pipe or areas of earth movement. The pipeline is monitored from the control center via the SCADA system on a 24/7/365

basis and any ground movements that caused the operational parameters to become unstable would alarm operators. In addition to these more established methods of monitoring ground movements, there are some new technologies that may enhance the ability of the operator to monitor ground movement and give even more ability for monitoring ground movements like frost heave or permafrost settling.

2.4.2.11 Operating Procedures

It is the intent of the Owner to establish operating procedures that will be specific to the pipeline system. These procedures will be developed after the detailed design of the system is established and the layout and types of equipment to be utilized are known, so that the operating procedures encompass how best to operate the system. However, for the purposes of this Application, provided below are some items that are typically included in the operating procedures:

- cathodic protection monitoring and maintenance procedure
- gas measurement data and gas quality data handling procedure
- hot work permit procedure
- lockout tag-out procedure
- confined space procedure
- personal protection procedures
- gas venting procedure
- surveillance procedure
- valve operating and maintenance procedure
- operating a pig trap procedure
- pig running procedure
- emergency shutdown procedure
- environmental monitoring procedure
- evacuation procedure
- procedures for doing work on:
  - electrical and instrumentation equipment
  - communications systems
  - valves
  - pumps
  - compressors
  - meters
  - vessels
  - welding

2.4.2.12 Audits and Inspections

A detailed audit and inspection plan for the O&M activities on the Pipeline will be developed during the execution phase of the Project, encompassing all O&M activities and the audit reports and recommendations will be subject to mandatory review by the Owner.

The objectives of audits and inspections are to ensure the company is meeting compliance of its internal procedures as well as external requirements. Audits usually look at:

- Achievement: Is there a measure to demonstrate the standards are being met.
- Quality: A measure of both subjective and objective observations with data that indicates the effectiveness, consistency and quality of the standard as seen in practice.
- Compliance: The requirements that have been implemented are being performed consistent with the expectations of the standard.

Audits and inspections are routinely carried out by internal and external personnel to ensure compliance is met or progressed forward on a continuous basis.

In addition to the on-going audit program, the Owner will undertake periodic audits to assure that the pipeline system is being operated in a safe and efficient manner. These audits will be undertaken by expert personnel independent from the Owner.

2.4.3 Operations and Maintenance Plan for the LNG Facilities

This section of the Application provides the outline of the O&M plan for the LNG Facilities (the "**LNG O&M Plan**") that will be developed for the Project. In this section, the Port Authority and its Project partners are referred to as the Owner.

2.4.3.1 Introduction

The LNG O&M Plan describes the activities required for operations input during pre-FEED, FEED, and detail design and to achieve a right-first-time commissioning and start-up and desired operational performance over the life cycle of the Project.

The LNG O&M Plan aims to give a basis for the future operation, and management of the LNG Facilities. It establishes the methods, and proposed organization that will meet the stated targets of performance. Most risks that are obvious in the LNG business, the facilities, and organization are identified, and methods to manage these risks are addressed.

2.4.3.2 Objectives

The main operational objectives for the LNG O&M Plan are:

- To ensure reliability of supplies of LNG on time, on specification, to establish the Project as a reliable supplier of LNG and to load all scheduled LNG carriers on time, without causing delays and or demurrage costs. To minimize environmental, health, and safety risks to the lowest, practical level.
- To ensure deliveries of LNG to the custody transfer points in the required quantity, quality, properly measured, and accounted for, at minimum cost, and on schedule in accordance to the agreed contracts.
- To safeguard the technical integrity of the assets, and all associated equipment at the LNG plant, and at the pipeline transfer points including the systems outside of the LNG battery limits by maintaining the plant operating parameters within the design safety limits of these systems at all times during the lifetime of the facility.
- To operate the LNG plant and equipment in the most efficient manner, in order to reduce, operating, & maintenance costs while being friendly to the local environment.
- To continuously develop, and implement business opportunities, within the operational jurisdiction of the facility, in order to maximize revenues.
- To optimize short-term cash flow without compromising the long-term business future.
- To minimize all operating, and business risks.
- To ensure that Alaska's LNG becomes an active and strong contributor to the local community, and the State economy.

The LNG O&M Plan will be updated on a regular basis as changes occur in Project development, operations of the facility, and as other circumstances dictates.

The Owner's LNG operations staff will assist the EPC contractor with pre-commissioning, commissioning, start up and performance testing of the facilities. All required resources will be made available to the contractor for the purpose noted above in accordance with the contract.

2.4.3.3 Manpower & Organization:

To achieve the above objectives a functional operations organization will be put in place. Following are the details of the operations organization both for commercial operations and during the project stages.

2.4.3.3(a) Organization General Principles

The intention of the operations organizational design is to minimize the organizational layers in order to improve the organizational efficiency. The operations organization will follow the functional structure that features the core departments: operations, maintenance and engineering.

The Owner's LNG O&M team will be appointed early in the EPC phase and should be allowed to gain general and LNG-specific knowledge and skill through a structured training program. The O&M team will join the project team during the EPC phase to review and assist in the development of operating procedures, working on the baseline inspections, populating the computerized maintenance management system and assisting the EPC contractor in the pre-commissioning, commissioning and start up of the LNG facilities.

2.4.3.3(b) Recruiting

The success of the start up and subsequent ongoing operation will depend to a large extent on the timely availability of appropriate staff. To ensure that the right people are available at the right time, a recruitment policy and associated principles will be developed.

The policy and principles shall form the basis for all recruitment activities for the lifetime of the LNG Facility and shall lead to the development of procedures that will ensure that staff are recruited and engaged in a timely and consistent manner. Furthermore, this policy and its related principles and procedures will form part of the human resource management system. This system shall provide as a minimum for position management, manpower management, and learning and competence management.

The policy will lead to the development, implementation and maintenance of an attraction and recruitment systems and processes to attract staff from local areas and other appropriate sources, and shall involve the recruitment of experienced and inexperienced staff.

2.4.3.3(c) Training and Development

Training against agreed competence standards for all project phases will be a key project objective. The training and development of the competency of staff is critical to the success of the project, and subsequent ongoing operation. The timing and coordination of training in the early phases of the project need to be managed to ensure that sufficient staff are available for commissioning-assistance and start-up.

2.4.3.3(d) Pre-Operations Operations and Maintenance Budget

Pre-operations costs are the Owner capital cost incurred to hire and train the operations staff and any other operational costs before the commencement of commercial operations of the LNG Facilities. These costs typically consist of two years operational spares and other general and miscellaneous expenditures before the start of the commercial operations. These have been estimated to be $45 million.

2.4.3.3(e) Operating Expenditure

O&M expenditure consists of manpower costs, maintenance costs, contract services and insurance and, land lease and marine charges, safety security and environmental certification, auditing. These have been estimated to be approximately $145 million per year.

2.4.3.3(f) Mobilization

One full time operations interface manager will be appointed during pre-FEED to provide operational input during the pre-FEED and FEED stage. Other resources such as a maintenance specialist, will be brought in on a as and when needed basis. One marine representative will also be available during the pre-FEED and FEED stage of the project.

Hiring of the operations staff will start during the construction stage. Appropriate training will be provided by the owners and the EPC contractor before they participate in the pre-commissioning and commissioning activities.

The typical build up of the operations organization during the EPC phase is shown below.

Table 6 Build Up of the Operational Organization for the LNG Facility

Phase	Pre-FEED	FEED	Detail Design	Construction	Construction	Construction	Pre-Commissioning Commissioning Start Up	Staff Train 2	Staff Train 3
Year	2008/09	2010	2011/12	2014	2015	2016	2017	2017	2018
No. in Place	2	4	4	4	10	120	175	207	238

2.4.3.4 Role of O&M Personnel Prior to Commissioning

2.4.3.4(a) Pre-FEED

A full time operations representative will be appointed during the pre-FEED. One of the main tasks for operations during the pre-FEED will be to ensure that lessons learned from the operating experience of similar LNG Facilities are incorporated into the basis of design for the Project. Operations personnel will also participate in the key reviews held during this period to ensure that the facilities can meet the operability, maintainability and reliability requirements. Operations personnel will also work with the contractor to optimize facilities layout and design basis for safety, access and maintaintenance ability. Marine functional representative will also be providing the input into the design of the marine facilities. Operational risk will be identified and will be put into the risk register.

2.4.3.4(b) FEED

Full time operations personnel involvement will continue during the FEED stage. Incorporation of lessons learned from the operating history of other LNG projects will be stepped up at this stage. A full time marine representative will also be appointed to the project at this stage to provide design requirement for the marine facilities.

The operations will also provide the input into the key design reviews. Key operations-related philosophies such as isolation philosophy, fire & gas philosophy, operations philosophy, maintenance philosophy, pre-commissioning and commissioning philosophy, start up, performance test and system handover philosophies, sparing philosophy, training philosophy etc. will be developed by the contractor and reviewed by the Owner's operations team during this stage.

All operational risk identified during this stage will be put into the Project risk register and will be followed up by the operations representative for satisfactory resolution.

Operations resource requirements during the execution phase, including manpower and budget required for the operational build will be refined and approved at the end of FEED. Activity-based operating expenditure for commercial operations will be prepared and approved by the end of FEED as well.

Operations personnel will also review the design to identify any new technologies applied, complex design issues etc. and will initiate appropriate studies such as flow assurance to incorporate results in the design for safe and smooth operation of the facilities. Operations personnel will develop a management of change procedure to ensure that areas for improvement from the lessons learned are fully considered and documented prior to implementation.

2.4.3.4(c) Detail Design & Construction

During the detail design stage the two years operational spares and the capital spares will be identified and ordered. The equipment critical for the reliability and availability of the facilities will be identified and for complex and difficult to maintain equipment long term service or healthcare type contracts to be put in place with the equipment manufactures or specialized vendor for proper care and maintenance.

A detailed pre-commissioning and commissioning execution plan will be developed by the contractor and reviewed by the Owner's operations personnel during the detail design and construction stage. Resource requirement to execute the pre-commissioning and commissioning activities will be detailed in the commissioning execution plan both for the EPC contractor and the operations personnel. The Owner will start the recruitment process so qualified and competent personnel are available for the execution of the pre-commissioning activities. EPC contractor will provide necessary training and competency assessment framework to ensure that the whole team is competent and qualified to execute the commissioning, start up and subsequent operation of the facilities.

Operations personnel will also be working closely with the PMT and the EPC contractor during the mechanical completion process. The relevant skill from operations will be involved to witness the tests on completion and will perform the final walk downs to ensure that the system is complete according to the design specifications. Any deficiencies in the system will be identified and fed back to the contractor for rectification before mechanical completion.

2.4.3.5 Role of O&M Personnel during Pre-Commissioning and Commissioning Activities

Typical activities to be performed by the contractor during the pre-commissioning stage are listed below along with the role of the Owner's O&M organization during this stage of the Project.

Pre-commissioning is an EPC contractor responsibility and includes checks, cleaning and tests required to ensure that permanent equipment and build materials have been installed and are ready for commissioning. The typical pre-commissioning activities performed by the contractor during this stage includes cold function checks for instruments, installation of temporary strainers, circulation of non process fluids for cleaning of vessels and piping systems, removal of temporary strainers, installation of the orifice plates, loading the first fill, nitrogen purging, leak testing, inerting of the system.

At this stage, some of the operational resources will be integrated with the contractor team for on-job training and to assist the contractor in the execution of the above activities. Others will be working closely with the PMT to monitor the work performed by the contractor for compliance with specifications, standards and procedures to ensure a smooth and flawless start up.

2.4.3.5(a) Ready for Start Up

On completion of the pre-commissioning and commissioning, the contractor will provide the Owner with the assurance that all the facilities are completed according to standards and are now ready to receive hydrocarbons. It is the responsibility of the contractor to provide full readiness-to-operate assurance to the Owner.

2.4.3.5(b) Start Up, Performance Test and Commercial Operation

Once the contractor and the Owner have agreed that it is safe to bring hydrocarbons into the LNG plant and start liquefaction operations, the facilities will be started in accordance with the operating procedures. The contractor is responsible for the start up and operation of the facilities till the time plant is handed over to the Owner. The contractor will be supervising the operations and performing the maintenance on the equipment according to the manufacturer recommendations. The Owner's operations team will be working with the contractor for hands-on training and at the same time monitoring the work of the contractor and performance of the plant.

The purpose of the performance test is to ensure that facilities can meet the design specification, can produce the volumes as specified in the contract while operating within the design and operating envelopes. Once steady state operation has been reached, the performance test will be executed according to procedures in the EPC contract documentation and/or to be developed by the Owner and the contractor during the EPC phase. The contractor will be responsible for arranging any specialist/vendor support if required for the performance test.

The performance test will demonstrate that contractor has completed the LNG Facilities subject to the warranty administration requirements. In the event the results indicate that the overall performance does not meet the design basis specification and performance guarantee figures, the contractor will follow up to execute corrective actions to meet the design basis requirement and performance guarantee.

Once the LNG Facilities are in stable operations, performance test results indicate that facilities can deliver the on specification product design volumes while operating with the operating envelop, and operating history indicates that the facilities can deliver the design reliability and availability, they will be considered ready for commercial operations.

2.4.3.6 Role of O&M Personnel During Commercial Operations

2.4.3.6(a) Operations

The Owner's operations department has the core responsibility of producing LNG. Key performance indicators for operations include safety, availability factor, thermal efficiency and operating cost. To deliver the contractual quantities specified in the LNG supply agreements, the LNG Facilities will have to be operated at the design availability and stream day capacity. In order to achieve this, the operations personnel will have to reduce the incidents which can result in loss of availability and stream day capacity. The operations department will develop collaborative arrangements and coordination with the upstream gas suppliers and with buyers of LNG, in order to optimize the utilization of the LNG Facilities.

The major cause of scheduled downtime is expected to be the required maintenance on the refrigeration gas turbines. The unscheduled downtime can be caused by number of reasons like foaming in treating section, pre-mature dryer breakthrough, heavy end freezing and high exhaust temperature on the turbine exhaust. LNG facilities typically develop operating and coordination procedures, training practices, and mitigation action plans to eliminate or mitigate all such risks.

2.4.3.6(b) Maintenance

The maintenance plan will be developed with the objective to deliver the desired performance for the LNG Facilities over the life cycle of the Project.

- The LNG maintenance team will manage routine maintenance and turnaround maintenance. For turnarounds and specialized maintenance contractors, including local contractors will be used.
- Maintenance will be based on risk and reliability management.
- The mechanical workshop shall be designed and managed to support maintenance.
- All maintenance work shall be captured, planned and recorded in the computerized maintenance management system.
- Long term service agreements may be put in place for the gas turbines, compressors, and control systems.

2.5 Project Cost Estimate

A summary of estimated Project capital costs, broken down into the principal areas of expenditure, is provided in Table 7 below.

Table 7 Indicative Cost Estimate

Item	Estimated Cost ($ billions)
Development Phase:	
Program Management	0.070
Pre-FEED and FEED	0.185
Surveys and Permitting Support	0.120
Regulatory Agency / Permitting Costs	0.045
Owner's Management Costs	0.105
Subtotal Development Phase:	***0.525***
Execution Phase:	
Pipeline and Compression Facilities	11.70
LNG Facilities	7.00
Owners Costs: Pipeline and LNG Facilities	4.40*
Subtotal Execution Phase:	***23.10***
TOTAL:	**23.650**

** Includes: Program management costs, escalation after 2007, owner's contingency, insurance, administrative and other owner's costs, ad valorem tax, pre-startup O&M and mobilization, linefill and licensing costs, but excludes financing costs (interest during construction, financing fees, initial funding of reserve accounts).*

It should be noted that the above figures and those in the following sections represent a **preliminary, indicative assessment of the costs**, based on provisional technical definition and schedule information. During the FEED phase, the engineering definition of the facilities will be further developed together with a detailed execution schedule and plans, which will enable a more detailed project cost estimate to be developed.

As required under section 2.5 of the RFA, the above cost estimate figures and those in the following sections are based on an assessment performed in the third quarter of 2007, and are shown on an unescalated basis.

2.5.1 Cost Estimate for Development Phase

The table below provides a summary of the estimated costs (in $millions) during the development phase, broken down by principal areas of activity and by year.

Table 8 Indicative Development Phase Costs ($ millions)

	2008	2009	2010	2011	2012	Totals
Program Management	5	13	25	17	10	70
Pipeline Pre-FEED & FEED	14	45	90			149
LNG Facilities Pre-FEED & FEED	7	10	19			36
Agency Permitting Costs			5	20	20	45
Surveys		30	35			65
Permitting Support				37	18	55
Owner's Management Costs	10	25	30	20	20	105
Total	**36**	**123**	**204**	**94**	**68**	**525**

The above activities are defined as follows:

- Program Management: Program management encompasses the activities required to support the project during this phase outside of the direct management and execution of those activities below. In addition to directing, controlling and coordinating the various work areas it includes setting up and maintaining a presence in Alaska in support of the survey activities and to work with the relevant agencies to pave the way for labor agreements and involvement of the Alaskan workforce. It includes dealing with a variety of external groups and interfaces, including those related to the permitting process in order to facilitate progress of the development phase work.

- Pre-FEED: Pipeline and LNG Plant: Pre-FEED activities are those essential to ensuring that the FEED process can begin and proceed in an efficient way, and include the establishment of the basic design parameters, of which one of the most critical will be the condition of the gas supplied at the ANS.

- FEED: Pipeline and LNG Plant: FEED includes final route and site selection, development of a firm and consistent basis of design for all facilities, development of the engineering definition to the point where the project cost estimate and detailed execution plans can be developed and ultimately to provide a robust starting point for subsequent detail engineering, environmental studies and assessments to support permitting (see below) and technology appraisal and selection.

- Survey Work: This includes surveying sites and Pipeline route to enable final selection to take place and the work to obtain the necessary geotechnical and environmental information to support engineering, for the development of mitigation measures and to support permitting.

- Permitting Support: Preparation of material for permit applications and liaison (e.g. providing clarification and/or supplemental information) with permitting and regulatory authorities and bodies.

The cost estimates for the development phase cover the period from the award of the License to the issue of notice to proceed and includes pre-FEED, FEED, the FERC application and support process and permitting activities. The period runs from the second quarter of 2008 to the fourth quarter of 2012. The cost estimate includes:

- all engineering activities;
- the permitting process;
- field surveys and data acquisitions;
- soil borings (nominally 400 for major crossings and 1,500 along the right-of-way) to supplement the data acquired during the surveys and/or that is not available within the public domain or YPC data;
- Pipeline center-line marking;
- the set-up and operation of Alaskan offices by the Port Authority and Project contractors; and
- temporary survey camps.

The estimates were prepared using a combination of data from similar activities on comparable projects adjusted to reflect the particular requirements of the present work. Where rates formed part of the calculation, these were taken from Bechtel's current company database. Resource requirements for activities such as surveys and geotechnical investigations were based on an appreciation of similar activities on other work, taking into account the access and logistical issues of the particular locations in Alaska.

The above costs exclude any detailed engineering and procurement costs that are expended during the development phase timeframe; these are included in the execution phase cost estimates provided in Section 2.5.2 below.

2.5.2 Cost Estimate for Execution Phase

The table provides a summary of the estimated costs broken down into the principal areas of activity during the execution phase:

Table 9 Indicative Cost Estimate for the Execution Phase

	Estimated Cost ($ billions)
Pipeline	11.70
LNG Facilities	7.00
Owners Costs and Program Management Contractor Costs	4.40*
Total:	**23.10**

* *Includes: Program management costs, escalation after 2007, owner's contingency, insurance, administrative and other owner's costs, ad valorem tax, pre-startup O&M and mobilization, linefill and licensing costs, but excludes financing costs (interest during construction, financing fees, initial funding of reserve accounts).*

The execution phase cost estimates were prepared using a variety of estimating techniques to build up an indicative cost. As there is little design definition available at this stage, the costs were arrived at by comparing costs from a variety of similar projects and making adjustments to reflect the differences of location, scope, timing and technical parameters.

Program management encompasses the overall direction and coordination of the EPC activities for the Pipeline and LNG Facilities, together with liaison with external groups, including those representing the Port Authority and/or its Project partners, federal and state agencies, ANS gas producers and NGOs. Regardless of the contracting strategy adopted for the Project, a development of this magnitude and complexity requires a significant management and coordination resource separate from the EPC management of the various elements. For further details, please see Section 2.3.1.1.a (Program Management) in the Project Execution Plan attached in Appendix PP.

The program management team includes:

- Project directorate (directors, contracts, accounting, HR);
- land and ROW manager;
- Project controls and report consolidation;
- quality assurance
- health and safety executive;
- oversight in engineering, procurement, traffic and logistics, and construction; and
- office administration.

The execution phase costs for the Pipeline and LNG Facilities include the project management costs, detailed engineering, procurement, logistics, subcontract management, cost of materials and equipment, and all subcontracted services including construction.

The scope, quantities and costs for the LNG Facilities are determined using current-day pricing for equipment, materials, site construction, home office services, freight and associated indirect costs on the basis of a similar reference LNG plant. Several major items were priced with budgetary vendor quotes and using purchase order prices from the reference projects. The estimate shows the cost for three trains, each developed separately and including dedicated off-sites and utilities.

The scope and quantities for the Pipeline reflect 48-inch pipe from the North Slope to Delta Junction and 42-inch from Delta Junction to Valdez, and two compressor stations. The estimate was prepared using current-day line-pipe pricing and estimates of labor costs in Alaska were derived from current construction industry data.

The following items, which are have been excluded from EPC cost estimate, are Owner's costs: license/permit application fees; FERC fees; State fees; ROW rental and/or acquisition; land rental and/or acquisition; cost of acquiring existing ROW rights and/or ROW information; operations costs prior to start-up including Owner start up team; operating costs post start-up – including warranties, consumables, operating spares and ongoing heave detection and mitigation; Owner's execution oversight team; Owner's offices; Owner's transport; import duties; taxes, duties and levies; community projects, removal of access roads, pads, etc.; ships and marine operations; currency exchange; cost of funds; escalation beyond Q3 2007; line pack gas; LNG imported for tank cool-down or process commissioning; licensor fees; impact of potential delays to project progress; costs associated with utilizing services of native Alaskan corporations; the costs of acquiring an existing federal grant of right-of-way or any existing technical data developed by Alyeska, YPC, ANGTS, the North Slope oil producers, or others which may be required for use by the Project; and any community improvement costs.

2.6 Project Schedule

The overall schedule for the Project is attached as Figure 15. This shows the proposed program from License award to first LNG shipment.

Starting from License award, expected in April 2008, 32 months have been allocated to prepare basic design, undertake detailed planning, and to issue the baseline estimate. The open season is scheduled to take place over six months in the third and fourth quarters of 2010.

Following open season and FERC issue of the draft EIS, FID is expected to occur in February 2012. Detailed engineering for the LNG Facilities and the Pipeline is scheduled to commence at this point, with NTP scheduled for the end of the third quarter of 2012 (a total of four years and six months from License award to NTP).

Following site preparations, camps installation and pipeline and LNG Facilities construction, first LNG product is scheduled for the end of the second quarter of 2017, with the second and third LNG trains following six and 12 months later, respectively.

The project schedule was developed using a fully integrated logic diagram to assure that the activities necessary to start up the plant are completed (by construction, procurement, and engineering) in the proper sequence. The master schedule has been sequenced so that the Pipeline construction and LNG Facility programs support each other, based on pipeline quality gas being made available at the inlet to the pipeline by the end of the second quarter of 2016.

Weather history and seasonal patterns were considered during the development of the schedule and the associated productivity assumptions.

2.6.1 Schedule for Development Phase

The development phase schedule is attached as Figure 16. During this phase of the Project, the initial focus of the work will be to obtain comprehensive site survey information and progress engineering activities to support the permitting process.

From License award in April 2008 through the end of the third quarter of 2009, during the pre-FEED period, the engineering focus will be on identifying the design criteria for the LNG Facilities and the Pipeline. Work will include defining the key design drivers from the Pipeline and LNG Facilities location surveys and geotechnical investigations, and also the other engineering activities required to support an initial RR#1 filing during the third quarter of 2009.

FEED will commence in the fourth quarter of 2009, and engineering will progress to further develop the design and provide the information required for the RR# 13 submittal by early third quarter of 2010. During FEED, the technical definition will be finalized and the Project cost estimate will be developed. The data created will also support the execution planning process.

Once FEED is complete, engineering will change focus to responding to clarifications or questions that might arise during the application and permitting process, as well as progressing the cost estimate to support the open season, currently scheduled to complete by late 2010. This phase will continue, with an overlap with the early execution phase engineering and procurement activities, until receipt of the NTP.

2.6.2 Schedule for Execution Phase

The execution phase schedule is attached as Figure 17. During the execution phase of the project, the focus of the work will be to advance engineering activities to support the detail design and subsequent construction of the LNG Facility and Pipeline. Detailed engineering will initially overlap with the development phase and is currently scheduled to begin in February 2012. This is tied to FID, which is scheduled to occur following the open season and after FERC issues the DEIS, but prior to NTP. Once this occurs, the full engineering and procurement activities will progress to support the anticipated NTP and receipt of letter to construct in late third quarter 2012.

Further detail of the schedule issues and key milestones within each element of the project are as follows:

2.6.2.1 Pipeline

The Pipeline schedule currently is shown to be the critical path for the Project. This path covers the permitting activities required to achieve the first NTP (including surveying, FEED and the submissions to FERC), the preparation of the campsites, and installation of the pipeline, hydrotesting and commissioning activities. The overall pipeline EPC schedule hinges on three critical issues: (1) timing of FID, (2) environmental planning, and permitting, leading to having timely NTP and construction permits in place, and (3) the sequencing of site preparation, camp installation and the subsequent construction activities during the summer and winter weather windows.

The schedule is based on the assumption that authorization to proceed with the front-end engineering design will be given before the end of 2009. During 2010, environmental planning and permitting activities will continue, including extensive coordination of the system design with the regulating agencies. The Project will complete route, geotechnical, and other field surveys, and complete all basic design definition to prepare for issuing most permanent material purchase orders and construction subcontracts. Some pre-commitments to vendors will need to be made during this phase for certain key items of permanent material in order to obtain needed vendor design data and/or to reserve shop/mill space for the project to ensure that the project's schedule can be supported.

Once FID is achieved and authorization to proceed with the full EPC effort has been issued by February 2012, formal award of purchase orders and construction subcontracts will commence. Material production will immediately follow for key long-lead items such as pipe, compressors, gas cooling equipment, pre-fabricated buildings, and large valves. The camps, and certain specialized construction equipment such as trenchers and pipe bending machines, will also be formally ordered immediately after FID.

The project will mobilize to the field after NTP in September 2012. The first phase will include preparation of campsites, airstrips, access roads, lay-down yards, material borrow sites and mobilization of some of the construction equipment. Also included in the first phase will be the mobilization and erection of some of the camps. Limited construction of the site pads for above-ground facilities, such as compressor stations and mainline valves, will also be completed during the first mobilization phase. The remaining construction equipment and camps will be mobilized the following summer in preparation for construction to begin in the summer of 2014.

The schedule is structured to ensure that most material has been fabricated and delivered and that all essential environmental planning and permitting activities have been completed prior to the start of full spread construction in the summer of 2014. The construction plan has been developed to make use of multiple spreads working both the summer and winter seasons by using a combination of snow/ice roads, gravel workpads, and graded right-of-way. This approach gives the project the greatest assurance of maintaining the schedule as the project is not limited to one type of weather condition in which to work.

Pre-commissioning is schedule to occur from July 2016 through December 2016, with Pipeline quality gas required to be available from the suppliers to begin commissioning in June 2016. The Pipeline is scheduled to be mechanically completed and ready for gas by the beginning of the fourth quarter of 2016. This is three months prior to the needed date at the beginning of 2017 for gas to be delivered to the LNG plant to allow for commissioning of the first LNG train. Follow-up inspection of the restored right-of-way will be conducted during the summer of 2017.

2.6.2.2 LNG Facilities

The high rainfall/snowfall at the Valdez site impacts the projected schedule for the mechanical completion of the process area. However, the cold winter temperatures have limited impact on the overall LNG Facilities completion, as the critical path is established by completion of the site preparation and the erection of the LNG storage tanks.

Delivery and completion of the LNG tanks is based on working a 60-hour workweek. No winter work will be done during the first winter until the outer wall has been erected and the roof has been raised. Once this work is completed, work on the interior portion of each tank will proceed without delay in winter conditions.

The long delivery items include the compressors and the turbine drives and fabrication and delivery of the cold boxes. During FEED the process, project, mechanical and plant design groups will progress definition in order to allow quotations to be obtained for these and other critical equipment items having long lead times.

Site preparation is scheduled to start a full year prior to starting actual construction. This requires removal of a significant amount of rock by blasting, clearing and grubbing of trees and underbrush with associated removal and disposal. This time will allow the LNG tank contractor to prepare the tank foundation to start construction in the spring of 2014 for the first LNG tank.

The start-up of the LNG plant requires gas from the pipeline, planned to be available at the beginning of 2017. Once gas is available, commissioning of the plant will commence, leading to first LNG from Train 1 at the end of the second quarter of 2017. Trains 2 and 3 will be operational six and 12 months thereafter, respectively.

2.6.3 Schedule Assumptions

The following assumptions were made in preparing the schedules:

Restraints:

- License award April 1, 2008
- no construction activities prior to issuance of NTP
- availability of existing Alyeska Pipeline Service Company infrastructure to support surveying and construction activities
- no NTP prior to FERC letter to construct

Constraints:

- weather
- permafrost construction limited to winter for trenching/lowering in
- Prudhoe Bay gas supply availability
- Alaskan Rail availability

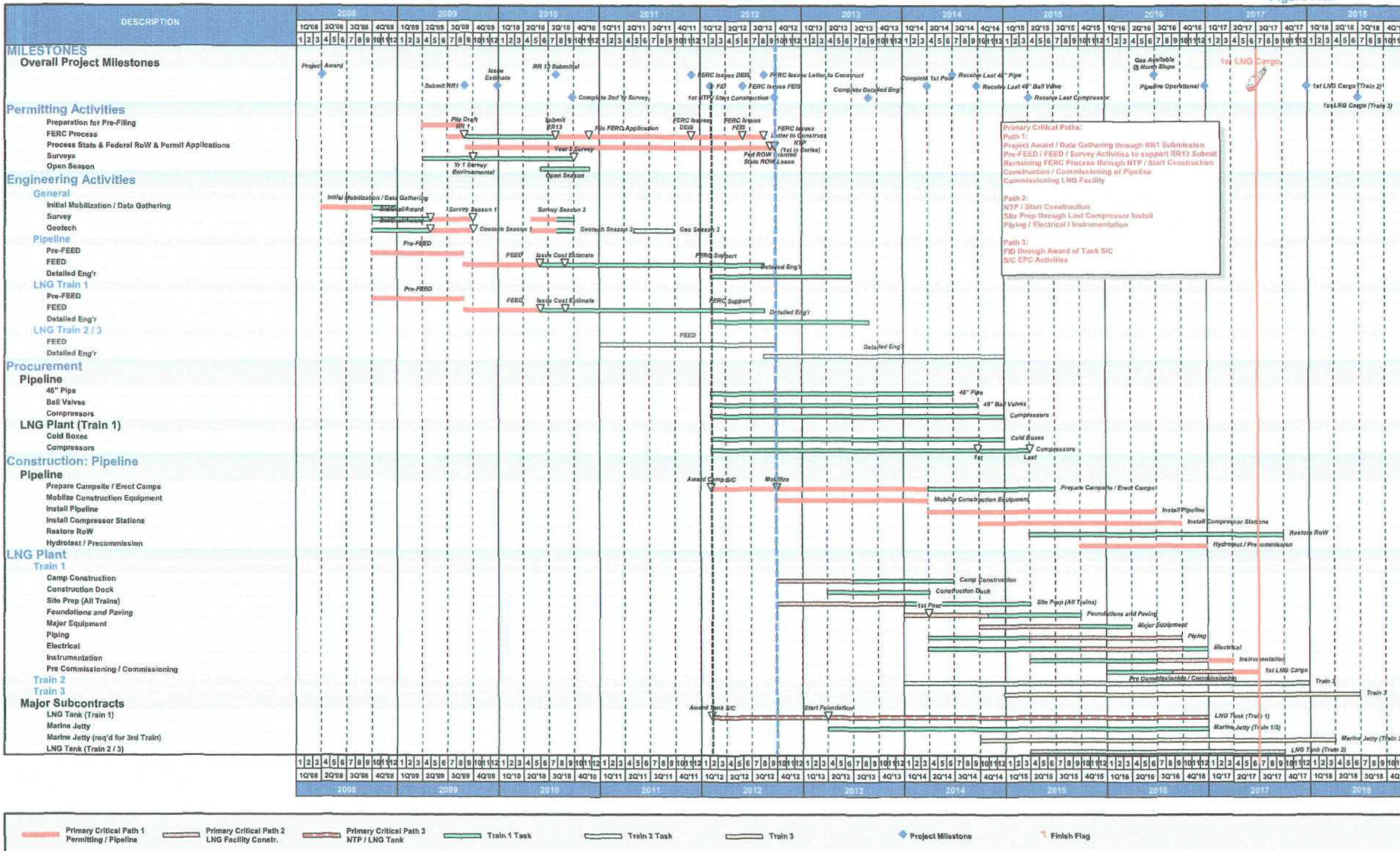
Basis and Assumptions:

- License Award April 1, 2008
- no design changes through the FERC process
- RR#1 information readily available for September 1, 2009
- RR#13 information obtained from normal FEED activities
- 9-month pre-FEED
- 12-month FEED to occur after pre-FEED activities are completed
- geotechnical survey permits in place to support 2009 summer season mobilization
- FID occurs prior to detail engineering
- assumes funding for all LNG trains (1, 2, & 3) FEED activities approved
- based on revised base case FERC schedule (38 months, RR#1 by September 1, 2009)
- LNG Facilities /Pipeline engineering activities performed in parallel
- no construction activities prior to NTP

- NTP required for site work at LNG facility
- authorization to procure detailed vendor prints for all equipment prior to NTP
- authorization to procure critical materials for long -lead items (includes but not limited to):
    - 48/42-inch pipeline pipe
    - 48/42-inch ball valves
    - LNG cold boxes
    - LNG tank subcontracts
    - Compressors
    - Marine jetty subcontracts
    - Heavy wall vessels
    - Flashing liquid expander
    - S/C for camps
- April 1, 2014 for first concrete pour at LNG facility
- sufficient labor is available
- LNG plant construction schedule based on previous experience
- LNG plant construction based on stick build for plant, subcontract execution for marine jetty and LNG tanks
- open season to be completed three months after issuance of cost estimate
- means of disposal for rock and overburden from LNG facility is readily available
- no unplanned weather downtime
- gravel mining occurs during summer months

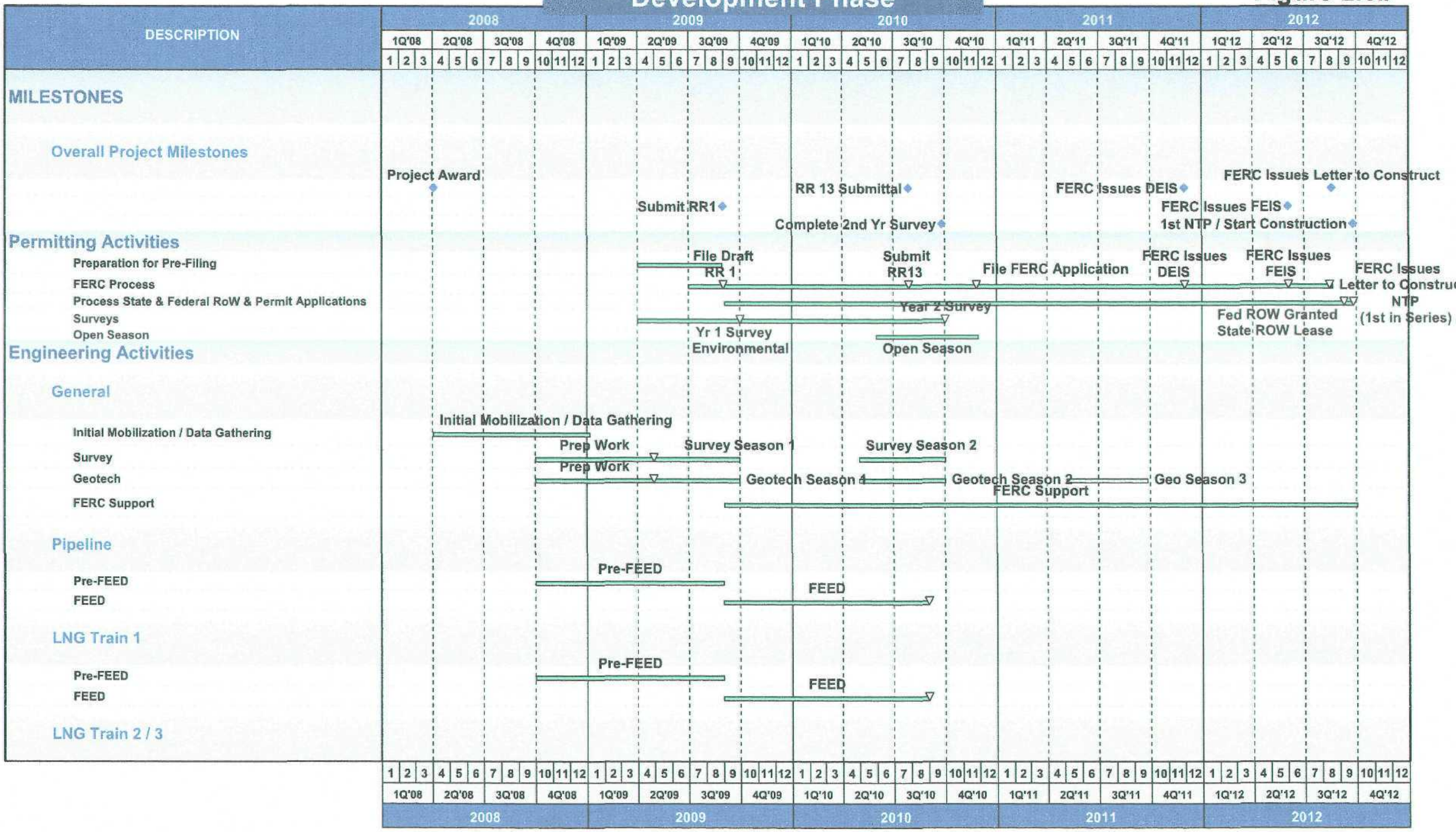
Alaska Gas Development Project
Milestone Summary Schedule
Base Case

Figure 2.6a



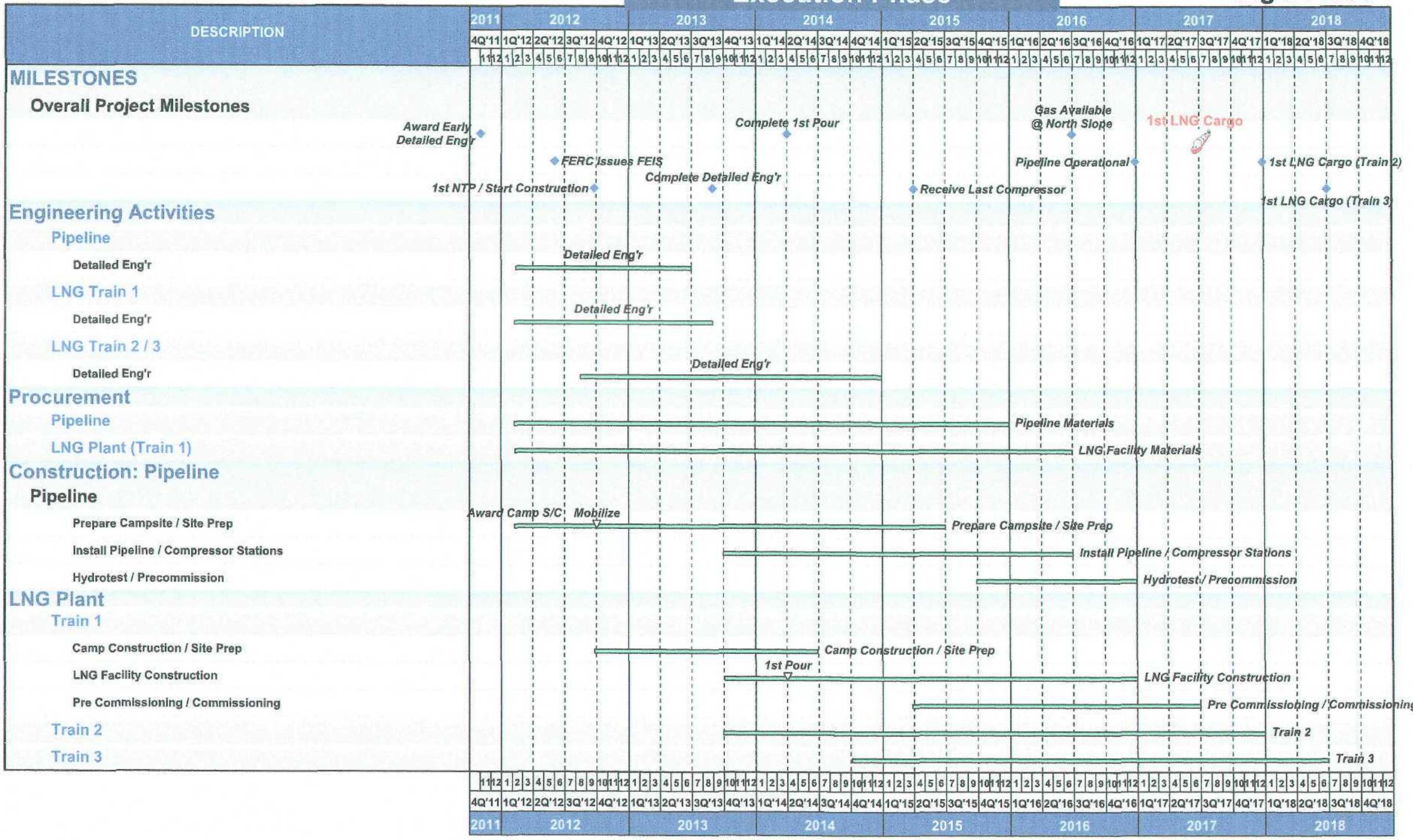
Alaska Gas Development Project
Milestone Summary Schedule
Development Phase

Figure 2.6b



Alaska Gas Development Project
Milestone Summary Schedule
Execution Phase

Figure 2.6c



2.7 Risk Assessment and Mitigation

This section addresses the risk areas identified in section 2.7 of the RFA.

2.7.1 Open Season and Firm Transportation Commitments

As described in more detail in Section 2.2.3.1(a), the Port Authority has designed the Project to mitigate the risks of an unsuccessful open season and unavailability of gas supply commitments. The Project design is based on a volume of approximately 2.7 bcfd, which mitigates the risks of: (a) unavailability of gas supply and firm transportation commitments due to insufficient gas reserves base to support a project with larger gas volumes; (b) potential delays associated with the need to discover, prove and develop additional ANS reserves; (c) potential delays associated with exceeding AOGCC Rule 9 offtake limits; or (c) potential delays in supply of gas from Point Thomson due to a requirement to implement a gas cycling/liquids extraction project prior to gas offtake.

In addition, the Port Authority believes there is an mitigation of the risks associated with committing Point Thomson gas under the open season because, as discussed in Section 3, the State is in the position to determine the terms of gas commitment and sale (subject to AOGCC determinations on cycling) in the re-leasing of Point Thomson.

Consequently, for the Port Authority's Project, risk relating to an open season and firm transportation commitments are associated largely with the risk that PBU working interest owners will not commit gas to the Project at the open season. However, given the Project's compelling economics and this Administration's handling of Point Thomson, the Port Authority is confident that the State will provide appropriate encouragement to those who hold a working interest in Prudhoe Bay to participate at an Open Season.]

2.7.2 North Slope GCP

As described above in Section 2.1.2, for the purposes of this Application it has been assumed that the GCP will be owned and operated by other entities. The Port Authority is currently in discussions with the Regional Corporation regarding its participation in the building, owning and operation of the GCP. The Corporation's experience and familiarity with the Alaska would provide a significant mitigant for technical and operational risks associated with the GCP.

2.7.3 Permits for LNG Export, Shipping, Import

Exports of natural gas from Alaska to nations other than Canada or Mexico requires a Presidential Finding under ANGTA. YPC applied for and received in January 1988 an authorization to export LNG from Valdez. Additionally, in 1988, the U.S. Department of Energy issued an order authorizing the export of gas to Japan, South Korea and Taiwan. This export license is for a period of 25 years for a maximum of 14 mmta. The specified

25 year period starts upon the first shipment of LNG from Valdez. The primary target markets for the Project are currently expected to be these same three countries.

The target markets for LNG from Valdez are outside the United States and therefore the marine transportation element of the Project will not be subject to the requirements section 27 of the Marine Merchant Act of 1920, commonly referred to the Jones Act. Please refer to Section 2.2.3.14(f) for additional details of the commercial plan for marine transportation services.

2.7.4 Availability and Costs of Labor Resources and Construction Equipment

Please refer to the Project Execution Plan in Appendix PP for a detailed discussion of risks associated with Project construction.

2.7.5 Rights-of-Way Acquisition and Environmental Requirements

The Port Authority will have access to the YPC permits, authorizations, data and related documents through the YPC Option Agreement with the Port Authority as detailed in the Regulatory Plan in Appendix OO. Such access to the YPC permits would mitigate the risks of delays associated with permitting and regulatory requirements and ROW acquisition. Among YPC documents included are:

(a) **Federal Pipeline ROW Grant**. A Federal ROW grant was issued to YPC on October 17,1988 to cross federal lands in the TAPS corridor for the construction, operation and termination of one natural gas pipeline and related facilities from Prudhoe Bay to Anderson Bay at Valdez. The document is attached as Appendix G-6.

(b) **State of Alaska Conditional ROW Lease** (December 10, 1988). A State of Alaska Conditional ROW Lease was issued to YPC on December 10, 1988. That ROW lease contains the text and stipulations of the Final ROW Lease that become effective when the Conditional ROW Lease requirements are met. It addresses the pipeline on state lands from the North Slope to Anderson Bay, within the TAPS corridor, in a manner consistent with the federal ROW grant. The document is attached as Appendix G-7.

(c) **TAGS Project-wide Final EIS**. YPC received a project wide FEIS in June of 1988 The EIS served as the NEPA compliance document on which all federal agencies based their permit application decisions. The document is attached as Appendix G-4.

(d) **FERC Anderson Bay Final EIS** (March 1995). YPC having fulfilled NEPA administrative review requirements, allowed FERC to issue place of export authorization. The document is attached as Appendix G-11.

2.7.6 Federal Loan Guarantee and Debt Financing

The Port Authority will take advantage of any available indirect or direct government financing. However, in order to present a conservative financing plan for the purposes of this Application, the Port Authority has not assumed any such government guarantees in its economic analysis for the Project.

As the Project is export-oriented, the Port Authority has assumed that it would not qualify for federal loan guarantees under the Alaska Natural Gas Pipeline Act of 2004, 15 U.S.C. § 721n (2006) and, therefore, the Port Authority has conservatively assumed no such government guarantees in its economic analysis for the Project.

2.7.7 Certificate Authority from the Applicable Jurisdictional Agencies

As discussed in the Regulatory Plan in Appendix OO, in 1987 FERC issued an order in which it declined to exercise discretionary authority under section 3 of the NGA to regulate the siting, construction, and operation of the pipeline component of the Project. FERC concluded that, in the case of exports of gas, unlike imports, ratepayers would bear no economic consequences of the pipeline. FERC further noted that the costs of the pipeline would be borne by the project owners, lenders, investors, and foreign gas purchasers. DOE subsequently concurred with FERC's determinations.

The Port Authority has assumed however that the Project will be subject to FERC regulation in order to mitigate the risk of delays associated with a potential jurisdictional dispute.

2.7.8 Operational Risks

Please refer to Sections 2.4.2 and 2.4.3 for a detailed discussion of operational risks and mitigation strategies.

2.8 Financial Plan

2.8.1 Description of Applicant and Participating Entities

The Port Authority is described in Sections 1.1 and 1.5.

For each Project component, the Port Authority intends to partner with world class energy companies with strong expertise and track record in their respective industries. The Port Authority is currently in discussions with a number of such prospective Project partners. The Port Authority has received, on a confidential basis, written expressions of interest from certain prospective Project partners to participate in the Project.

It is the Port Authority's intent to negotiate definitive Project participation agreements with the prospective Project partners after the issuance of the License. The Port Authority has not to date entered into definitive and binding participation agreements, as it believes that at the present stage of Project development it would not be appropriate to do so. Any binding commitments entered by the Port Authority at this stage may ultimately prove to be detrimental to the Project's economics and development prospects, for the reasons outlined below:

(a) The detailed technical definition that would be developed during the Project's development phase is yet to be performed and, therefore, the risks associated with such uncertainty would result in any prospective partners demanding a significant risk premium for any binding commitment at this stage.

(b) The definitive commercial arrangements for gas supply and/or firm transportation commitments will be obtained after the open season. The potential gas commitment volumes and commercial preferences of likely prospective shippers who would participate in the open season will become increasingly known as the development phase progresses. As gas supply arrangements are critical to shaping the commercial structure of any gas or LNG project, definitive downstream commercial arrangements should not be agreed prematurely, as doing so may reduce the flexibility of the Project to accommodate the commercial preferences of upstream gas producers, potentially resulting in diminished interest by upstream entities in participating in the Project's open season.

(c) Certain Project components, such as the marine transportation services, are expected to be procured pursuant to a competitive tender process, at early stages of the execution phase, as is customary for many LNG projects.

In addition, it is the intention of the Port Authority to work with Alaska Native Corporations in areas of the Project that are determined to be appropriate for participation by such corporations. Initial meetings toward that end have proved to be very positive.

2.8.2 Demonstration of Financial Resources

As described in the preceding section, the Port Authority will execute definitive participation agreements following License issuance with strategic partners with significant industry experience. Such strategic partners, including prospective partners currently in discussions with the Port Authority regarding Project participation, will provide Project funding during the development phase and will have adequate financial resources to achieve Project success.

It is anticipated that Project construction and operation will be financed on a limited recourse project finance basis, as described in Section 2.8.3 below, whereby upon Project completion, the inherent economics of the Project and its cash flow generating capacity constitute the primary credit and form the basis of financing. Because the Project benefits from strong economics, it is anticipated that it would be successful in obtaining third party debt funding on a project finance basis.

2.8.3 Financing Plan

At present, the Port Authority envisions the implementation of a limited recourse project financing to raise debt for the Project which would complement the equity commitments and other financial undertakings to be provided by the strategic partners: The Port Authority has included a copy of its confidential financial model with this Application in Appendix NN.

In compliance with AS 43.90.130(10), the Port Authority commits to propose and support Pipeline rates that are based on a capital structure for ratemaking purposes that consists of not less than 70 percent debt. The assumed base case debt to equity ratio for the Pipeline at this time is 75:25.

2.8.3.1 Senior Debt Financing

The Port Authority will take advantage of any available indirect or direct government financing. However, in order to present a conservative financing plan for the purposes of this Application, the Port Authority has not assumed any such government guarantees in its economic analysis for the Project.

As the Project is export-oriented, the Port Authority has assumed that it would not qualify for federal loan guarantees under the Alaska Natural Gas Pipeline Act of 2004, 15 U.S.C. § 721n (2006) and, therefore, the assumed interest rates include the risk premium associated with obtaining conventional, non-guaranteed project financing.

Potential debt financing options for the Project include tax-exempt financing under the Internal Revenue Code ("**IRC**"). The Internal Revenue Service ("**IRS**") has determined that the Port Authority is a political subdivision of the State, meaning not only is its income exempt from federal income taxation it may issue tax-exempt bonds. However, as currently configured, most of the Project may not qualify for Port Authority or State of Alaska tax-exempt financing under the rules governing private activity bonds. The Port Authority is currently considering conduit financing of portions of the Project via the Alaska Railroad Corporation's ("**ARRC**") ability, under IRC, 26 U.S.C. § 149(c)(2)(C)(ii) (2006), to issue tax-exempt bonds outside of the private activity limitations as in keeping with the broad transportation function contemplated by the Alaska Railroad Transfer Act, 45 U.S.C. § 1207 (2006). The Port Authority will work with the ARRC to identify portions of the Projects, such as the Pipeline or the LNG Facilities, suitable for tax-exempt financing opportunities. This would include, to the extent deemed necessary by bond counsel, seeking an IRS letter ruling affirming the tax-exempt status of a future issuance.

2.8.3.2 Equity Financing for the LNG Facilities

It is expected that the equity portion for the LNG Facilities would be provided by prospective strategic partners to the Port Authority.

2.8.3.3 Equity Financing for the Pipeline

For the Pipeline, the Port Authority is considering the following options for funding the equity portion of the financing:

2.8.3.3(a) Private Equity Participation from Strategic Partners

This is the base case option which has been assumed for the purposes of the Project economic analysis presented in this Application.

Under this option, it is assumed that the Port Authority would partner with a pipeline company and/or other equity investors to fund the equity portion. It is expected that such strategic partner(s) would participate on the basis of obtaining at least the customary ROE levels approved by FERC for ratemaking purposes. Recently approved rates for interstate pipelines have been based on an ROE component of 14%. This is the level assumed in the base case economic analysis in this Application.

Based on discussions with at least one prospective Pipeline participant, the Port Authority believes that it is likely that Pipeline strategic investors may require for their participation and seek approval from FERC a level of equity return higher than the 14% level of recently approved pipeline projects. Such an expectation of a higher return would be based on a perceived higher-than-normal risk associated with this Project, including the incremental economic risks to the Pipeline owners resulting from any cost overrun sharing scheme that might be implemented in order to incentivize shipper participation in the open season.

To mitigate the risks to the State of such a requirement by Pipeline equity investors to receive a higher level of equity return, the Port Authority is proposing to explore with the State the alternative equity financing option proposed below.

2.8.3.3(b) State Participation in the Pipeline

The option presented in this section is not a required condition by the Port Authority and is presented merely as an alternative for the State's consideration.

The Port Authority believes that the State should explore participation in financing of the Pipeline, either as a direct investor (either in the form of equity participation or subordinated loans) or as a financial guarantor to the equity portion of the Pipeline funding, assuming the risks customarily born by the equity investors in pipeline projects, including completion risks, risks of a failed open season, shipper credit risk, etc., including the risk associated with any scheme to incentivize shipper participation in the open season by sharing cost overrun risk through a sliding scale adjustment to the ROE level in the tariff, based on the divergence between actual and budgeted costs, as described in Section 2.2.3.6.

As the State is in a better position to evaluate the above risks than outside investors, especially the risks associated with shipper participation and ANS upstream gas development, it may be comfortable with receiving returns on its investment that might be lower than those demanded by outside investors. Any such lowering of the level of rate of return would be partially recovered through higher upstream revenues from royalties and taxes resulting from a lower Pipeline tariff and, more importantly, may provide a key ingredient in incentivizing shipper participation in the open season and ensuring that ANS gas monetization finally becomes a reality.

2.9 Performance History and Project Capability

The Port Authority was formed in 1999 as a municipal port authority under State law by the City of Valdez, the Fairbanks North Star Borough and the North Slope Borough. It is a single purpose entity created to build or cause to be built a natural gas pipeline from Prudhoe Bay to Valdez. It consequently does not have an operational history.

The Port Authority's approach, from the beginning of its formation, has been to enlist the participation of world leaders in the development of large-scale oil and gas projects for expert advice in the areas of: engineering and design, cost estimation, economic modeling, LNG shipping, and LNG and NGL marketing. It is thus through strategic partnering that the Port Authority will have the readiness, financial resources, and technical ability to perform the activities specified in this Application. The Port Authority, as is the case with the other 160 port authorities across the country, will contract with qualified, industry recognized companies to perform the various functions necessary for the construction, operation and maintenance of the Project.

The remainder of this section presents performance history of the capabilities of the Port Authority's partners and entities that have participated in the preparation of, or provided input under in this Application. The requirements of RFA section 2.9.1 (History of Compliance with Safety, Health and Environmental Requirements), RFA section 2.9.2 (Capability to Follow a Detailed Work Plan and Schedule) and RFA section 2.9.3 (Capability to Operate within a Cost Estimate) are addressed in the information provided for Bechtel in Section 2.9.1 below.

2.9.1 Bechtel

Bechtel has been engaged in the planning, management, engineering, procurement, and construction of petroleum refineries, chemical and petrochemical plants, gas and liquids pipelines, oil and gas production facilities, and LNG plants for more than 60 years. During that period, Bechtel has successfully completed more than:

- 375 major chemical and petrochemical projects;
- 265 refinery expansions and modernizations;
- 110 gas processing plants;
- 50 major oil and gas field developments (20 offshore, 30 onshore); and
- 85,000 km of pipelines, including oil, natural gas, slurry, multiphase, and refined-product systems in all types of environments.

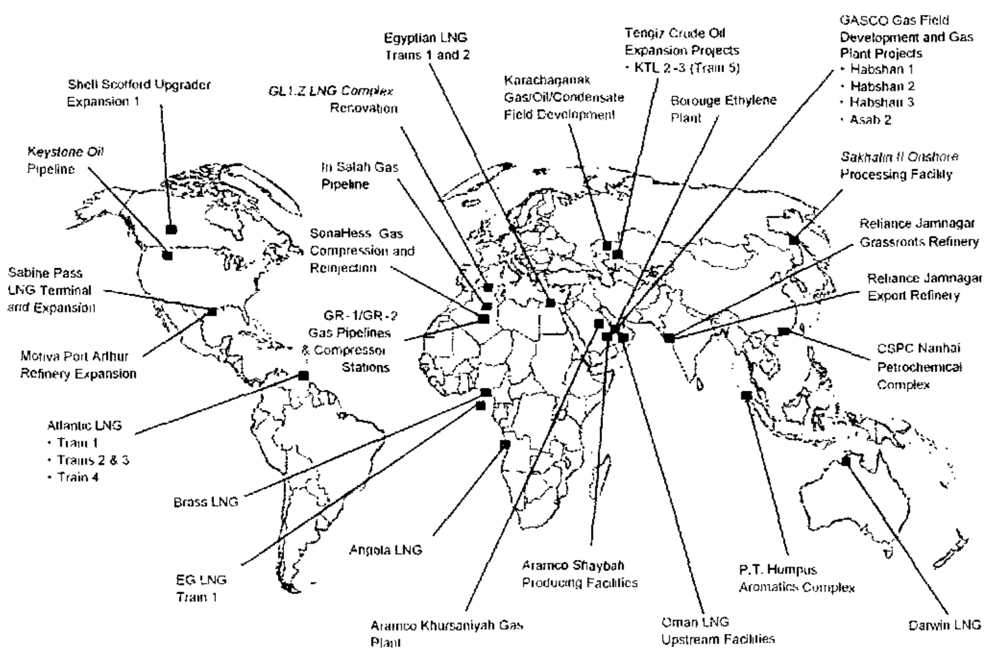
Bechtel has also been responsible for more than 35 percent of the world's current LNG capability, and is moving aggressively to expand our role in advanced energy technologies and alternative fuels.

Bechtel-built facilities encompass virtually every process and material handling technology available. This experience, coupled with long-standing relationships with process licensors, equipment manufacturers, and potential subcontractors, makes Bechtel uniquely qualified to deliver optimum performance, aggressive schedules, low installed cost, and safe design, construction and operation on the largest and most challenging EPC projects. Bechtel's reputation for quality performance and "making the impossible possible" is recognized throughout the industry.

Over the past 10 years, Bechtel has successfully completed more than 50 major projects for customers in the oil, gas, chemical, and pipeline industries. Many of the projects have involved work at remote locations characterized by harsh climatic or environmental conditions. As a result, Bechtel has an in-depth understanding of key execution issues such as provision of logistical support to remote project locations, movement of heavy modules and construction materials, preservation of fragile ecosystems, and maintenance of safe working environments under extremely adverse conditions.

Thirty of the most important projects that Bechtel has executed for customers in the oil, gas, and pipeline industries over the past 10 years are illustrated in Figure 18 below. Each of them has involved the combination of innovative thinking, technical expertise, and proven execution and management systems to meet our customers' cost and schedule goals. Taken together, they demonstrate that Bechtel has the capability to successfully execute major projects in the harshest and most challenging areas on the planet.

Figure 18 Recent Bechtel Oil, Gas, and Pipeline Projects



Following are case studies of six challenging EPC projects that demonstrate Bechtel's commitment to safety and ability to meet aggressive schedules and deliver within budget. These projects include:

- Habshan 2 Gas Development Project;
- GR-1/GR-2 Gas Pipeline and Compressor Stations;
- In Salah Gas Project;
- Jamnagar Refinery and Petrochemical Project;

- Tengiz Oil Field Development Project; and
- Borouge Petrochemicals Project.

Abu Dhabi Gas Industries Ltd. (GASCO)
Habshan 2 Gas Development Project
1998 – 2001

The Habshan 2 Gas Development Project demonstrated Bechtel's ability to design, build, and manage a very large, complex oil/gas field project in a remote location while meeting rigorous customer cost, schedule, and safety goals. Bechtel, in a 50-50 joint venture with Technip, provided engineering, procurement, construction, commissioning, and start-up services for the $1.4-billion project to expand the capacity of the Habshan gas processing complex. The project was executed using an integrated joint venture approach in which Bechtel had complete responsibility for the combined Bechtel/Technip team. Subcontracts were established for construction, field-erected tanks, and sulfur recovery units under Bechtel's management and supervision.

Project Scope

The Habshan 2 Gas Development Project involved the provision of new gas gathering facilities in the Bab field, a new gas processing and treatment complex capable of processing approximately 1 billion scfd of natural gas at Habshan, and associated export pipelines. Major facilities included a single-train gas separation/stabilization unit, three MDEA gas treating trains, two dehydration/ dewpointing units (including a demercurization unit), three sulfur recovery units, a steam generation and condensate unit, and more than 62 miles of 42-inch pipelines. The project also involved the revamp, upgrading, and integration of existing process and utility units; expansion and integration of existing offsites, product loading, and export facilities; upgrading of control systems including SCADA; and construction of 41 new buildings.

Cost Performance

The Habshan 2 Gas Development Project was a fixed-price contract requiring extremely tight controls and constant management review to ensure that every company on the project team stayed within budget. Bechtel implemented its proven project controls system, reporting procedures and processes to maintain effective control throughout the project, and delivered it within the approved budget.

Schedule Performance

In order to meet the customer's aggressive schedule goals on this complex project, Bechtel established design centers in five separate locations—Paris, London, Kansas City, Athens, and Abu Dhabi—providing virtually round-the-clock engineering capabilities. Home office engineering (more than 1.3 million job hours) was spread among the five design centers to make the most effective use of available technical resources, and the centers were linked electronically to ensure effective communication and sharing of data. After project award, the client imposed numerous adjustments and changes to the original scope definition resulting in substantial design changes. The project team was able to incorporate the changes into the overall design without impacting the overall schedule.

Bechtel developed a detailed traffic and logistics plan early in the project to organize and control the movement of personnel, equipment, and material required to execute the project. At peak, more than 9,000 construction management and craft personnel drawn primarily from six nations were deployed at the site. In addition, we provided more than 600 pieces of equipment, 18,000 tons of piping, 1,550 miles of electrical and instrumentation cable, and 98,000 cubic yards of concrete. As the project neared completion, dedicated integrated teams from the construction and commissioning organizations were set up to execute plant completion and hand-over activities to ensure the customer's gas-in requirement date was met.

Bechtel met all major project milestones and delivered the completed project on schedule and within the approved budget. Bechtel was able to accommodate numerous customer changes in scope definition and approach during the early stages of the project and delivered a high-performance plant on schedule while still achieving a record-setting safety record.

Safety Performance

The main Habshan 2 facilities were built alongside an operating plant. Providing a safe environment for the 9,000-person multicultural workforce was a primary concern throughout the project. To address these safety concerns, Behtel set up a series of project safety action teams at the site. Each team was made up of personnel at every level—from project managers to laborers—drawn from every company working at the site. The teams implemented an innovative program known as the "School of CRUEL" (Crew Re-education Using Elementary Lessons) that improved safety awareness and convinced the workforce that safety was something they could influence. The integrated team approach helped us to achieve a safety record of 33 million job hours worked without a lost-time accident and earned the Habshan 2 project a place in the Guinness Book of Records.

Customer Satisfaction

The best indication of customer satisfaction was GASCO's willingness to award Bechtel the front-end engineering and design (FEED) contract for the Habshan 3 project, the third phase of its program to expand the capacity of the Habshan gas processing complex. GASCO further demonstrated its confidence in Bechtel's capabilities by including several additional scope elements in the award, making it one of the largest FEED contracts ever awarded in the Middle East.

Sonatrach
GR-1/GR-2 Gas Pipeline and Compressor Stations
1997 - 2000

The GR-1/GR-2 Gas Pipeline and Compressor Stations project demonstrates Bechtel's ability to plan, control, design, construct, and manage complex pipeline facility projects in remote locations ahead of schedule and under budget. It also illustrates our capability to provide safe work areas and accommodations in hostile environments characterized by internal conflict. Bechtel had full engineering, procurement, and construction responsibility for the project scope, including civil, piping, mechanical, electrical, instrumentation, and telecommunications work during both the design/procurement and construction phases of the project. Bechtel constructed the job on a direct-hire basis, using subcontractors for limited work scopes including area paving, pipe coating and painting, air transportation, and security services.

Project Scope

The GR-1/GR-2 was developed to enable Sonatrach to meet increased gas demand for local consumption and export by doubling the amount of gas transported through a twin 48-inch, 318-mile pipeline system. Because of its magnitude, the project was executed in three construction states:

- Northern Pipeline Section: 531-kilometers of 48-inch gas pipeline with 22 mainline valves and seven scraper trap stations connecting Rhourde Nouss and Hassi R'Mel.
- Southern Pipeline Section: 232-kilometers of 42-inch gas pipeline and 201 kilometers of 48-inch gas pipeline with 19 mainline valves and seven scraper trap stations connecting Alrar and Rhourde Nouss.
- Compressor Stations: A total of 10 turbo-compressor units at four compressor stations. Compressor station facilities included centrifugal compressors driven by aero-derivative type LM-2500 gas turbines, turbo-alternators, discharge gas coolers, inlet gas separators, buildings, station piping, electrical, instrumentation, and a distributed control system.

Work on the pipeline sections was completed in 1998. Work on the compressor stations was completed in 2000. The GR-2 pipeline, which runs between Rhourde Nouss and Hassi R'Mel and parallels the existing GR-1 pipeline, was also built by Bechtel and completed in 1996.

Cost Performance

The project was executed by Bechtel on a lump-sum, turnkey basis. However, Bechtel worked closely with Sonatrach throughout the life of the project to evaluate scope changes and other client requests and develop ways to accommodate them within the contract framework, rather than adhering strictly to our contractual obligations. Negative change orders were negotiated whenever possible to compensate for requested changes that increased the cost of the project, and we accepted significant additional work scope during the course of the project without modifying the original completion date. Bechtel implemented its proven project controls system, reporting procedures and processes to maintain effective control throughout the project and delivered it within the approved budget as adjusted to accommodate client-approved scope changes.

Schedule Performance

To ensure that Bechtel would meet the aggressive schedule in a hostile environment, Bechtel initiated mobilization of the project, both in the office and on site, as early as feasible. Bechtel began engineering prior to the effective date of the contract and the turbine/compressor vendors agreed to begin engineering work on the machines prior to release of purchase orders. These actions resulted in early equipment delivery to the site. Prior to the arrival of the equipment, we established training programs for local personnel and began erecting shelters and constructing foundations for the machines. In addition, we used prefabricated metal buildings whenever possible to reduce construction costs and enhance the construction schedule.

Bechtel engineering and procurement was performed in tandem to ensure material was delivered to the site on time to meet our aggressive schedule. To make sure material and equipment delivered to the site was the highest quality possible, Bechtel placed several resident engineers in vendors' shops to ensure that the production and testing of equipment went smoothly, and documentation was prepared and conducted in a timely manner. This strategy reduced the need for rework at the site or the possible rejection of equipment delivered to the site, allowing us to meet our budget and schedule *requirements.*

Despite the difficult logistics and security climate inherent to the project location, the project was completed five months ahead of Sonatrach's aggressive contract schedule and all performance tests met the contractual guarantees.

Customer Satisfaction

Bechtel maintained a strong, lasting, positive working relationship with Sonatrach throughout the project. Sontrach has repeatedly expressed satisfaction with the completed project and regularly include the four compressor stations on official visits to existing facilities. The best indication of their satisfaction with the GR-1/GR-2 Gas Pipeline and Compressor Stations project was their willingness to award the 460-kilometer, 48-inch In Salah Gas Pipeline project to virtually the same Bechtel team in August 2001.

Reliance Petroleum Limited
Jamnagar Refinery and Petrochemical Project
1995 – 1999

The Reliance Jamnagar Refinery and Petrochemical Project demonstrates Bechtel's ability to manage a very complex project involving multiple process units, a 70,000-person workforce, and challenging environmental conditions from conceptual design through project completion and beyond. Bechtel provided overall project management, engineering, procurement, construction management, and commissioning services plus startup assistance. Bechtel was directly responsible for performing approximately 40 percent of the work and maintained overall management and control of the entire project. Construction was subcontracted primarily to local Indian companies.

Project Scope

The 450,000 bpsd, integrated refinery and petrochemical facility in Jamnagar, India, contained 46 process units in five major processing complexes, including a crude distillation and hydrotreating complex, a fluidized catalytic cracking and olefins complex, a delayed coker complex, an aromatics complex, and a polypropylene complex (designed and built by others). Process designs for all units in Bechtel's scope were based on process vendor UOP's proprietary technology. Bechtel also designed and built a power plant, a desalination unit and water distribution facilities, a tank farm, a remote marine terminal for import of crude oil and condensate feedstock and export of refined products, and the infrastructure required to support a workforce that, at peak, exceeded 70,000 people.

Bechtel was involved in the project from its conceptual stage through basic design and into detailed execution as part of an innovative partnership-type arrangement with Reliance and UOP. A team of UOP, Bechtel, and Reliance personnel came together to perform a wide range of configuration, optimization, and value engineering studies; fuel and loss studies; and marine and logistics studies. Out of that extensive study and evaluation effort, the team developed a basic design tailored to Reliance's unique requirements regarding efficiency, total installed cost, procurement phasing, and design flexibility.

Cost Performance

From the beginning, Bechtel recognized that we had to approach this very large, very complex cost-reimbursable project with a fixed-price mentality to make sure the project team would meet its budget goals. Bechtel applied its proven project controls system, reporting procedures, and processes to maintain effective control throughout the project, and engaged senior Reliance management in high-level reviews to ensure that all parties maintained a focus on cost.

Throughout the project, Bechtel worked closely with Reliance to develop the most cost-effective solutions to use in a country where labor was inexpensive while materials were costly. For example, Bechtel reduced the cost of the 124 crude oil and products storage tanks required by bringing on additional engineers to produce tank designs, purchasing the steel separately and awarding fabrication contracts to Indian tank constructors, rather than relying on an international specialty contractor to provide the tanks on a turnkey basis.

Schedule Performance

To deal with the size and complexity of this grassroots project, we utilized teams of engineers working in London, Houston, New Delhi, and Jamnagar to generate the more than 80,000 engineering drawings needed to keep pace with construction. The four centers were electronically linked and tied in to a common electronic document management system. We also developed the world's largest 3-D CAD model with 1,600 miles of plant piping modeled. The four execution centers worked simultaneously on the model from nearly 500 PDS workstations, effectively achieving round-the-clock productivity. We used Bechtel's electronic communication system to transfer engineering documents simultaneously among multiple offices and suppliers, while three-dimensional computer models could be generated and reviewed in London and immediately sent to Reliance headquarters in Bombay and to the project site.

The massive size and weight of some of the equipment required for this project posed significant challenges not only in delivering it to the site, but also installing it. To meet those challenges, Bechtel and Reliance implemented the most intensive heavy lift/heavy haul program ever undertaken at a jobsite. The program involved 350 cranes (including five super-heavy cranes), 700 heavy lifts, and 26 super-heavy over-dimensional cargo (ODC) lifts, and was executed within a six-month accelerated lift schedule. Each super-heavy lift took approximately one week and 20 crane movements to execute. The largest vessel handled on the project weighed 1,600 tons and measuring 244 feet in length. Special cargo-handling facilities—including a permanent loading jetty, a permanent roll-on roll-off (RORO) jetty, and two temporary RORO jetties—were installed at the Port Reliance anchorage in the Gulf of Kutch to handle cargo arriving by ship. In all, more than 80 cargo vessel shipments were unloaded at the anchorage. Once at the anchorage, ODCs were transferred to barges while equipment weighing more than 440 tons was loaded onto the special RORO jetties. Shore cranes and ROROs were used to move vessels from the barges to self-propelled modular transporters for transport along a specially built haul road to the refinery site for erection upon arrival.

Despite having to deal with a major cyclone at the peak of construction, Bechtel successfully met the schedule requirements established by the customer during conceptual design and delivered a fully operational facility on schedule.

Customer Satisfaction

Reliance demonstrated its confidence in the quality of Bechtel's work on the Jamnagar Refinery and Petrochemical Project by retaining Bechtel on a sole-source basis to work at the refinery following mechanical completion in 1999. In 2005, following a series of successful expansion and upgrading assignments, we began work on a new export-oriented refinery located adjacent to the existing facility. The new refinery will increase the overall capacity of the Jamnagar complex to 1.2 million barrels per day and make it the largest refinery in the world while allowing it to process a wider range of crude oil feedstocks and produce higher value products.

TengizChevroil (TCO)
Tengiz Oil Field Development Project, Kazakhstan
1993 - Ongoing

The Tengiz project demonstrates Bechtel's ability to provide a sustained level of ongoing services at a remote location with no direct coastal access and to provide a full range of oil field and infrastructure facilities. This project also illustrates Bechtel's commitment to utilize a high percentage of indigenous workers and provide a large-scale transfer of skills to the local workforce. The project includes both the revamp of existing oil production facilities and the installation of new oil and gas processing facilities, including gas-oil separation units, plus facilities for the generation and distribution of electric power, steam, and water.

Project Scope

Bechtel, in a 50-50 joint venture with the Turkish construction company ENKA, has been providing engineering, procurement, and construction services to enhance oil field operations at Tengiz since 1993. Bechtel's first assignment was as project services contractor to help develop the Tengiz infrastructure, including general utilities and roads. Since 1996, our scope of work has grown and now encompasses engineering, procurement, and construction for capital projects and general services, including:

- Revamping of existing oil processing facilities to increase capacity;

- The Train 5 project, a several hundred million dollar new oil and gas processing plant, which includes an oil and gas separation unit, power generation, boiler plant, and utility distribution; and
- Construction services contracts for TCO's sour gas injection (SGI) and second-generation project (SGP), which cover construction of oil and gas processing and power and utilities units for the SGP and installation of main compressors and processing equipment for the SGI and will increase TCO's crude-oil production capacity from 13 million tonnes per year to between 20 million and 23 million tonnes per year.

To date, Bechtel has been involved in excess of $1 billion worth of contracts at Tengiz.

Cost Performance

Bechtel has established a flexible system of project control and reporting procedures that enables us to effectively meet TCO's budget goals on multiple projects characterized by frequent changes of scope, contracting approach, and government policy.

Shortly after starting the Train 5 Expansion project, TCO informed us that they had purchased a large amount of capital equipment for another project and wanted us to incorporate as much of it as possible in Train 5. After evaluating the material, we identified approximately 100 items, including major vessels, pumps, compressors, heating, ventilation and air conditioning (HVAC) equipment, and control valves, suitable for rehabilitation and use. We tested and refurbished the equipment, made modifications to meet project requirements, installed the equipment at the site, and achieved significant capital cost reductions and schedule savings.

In addition, due to the remote location at Tengiz, Bechtel decided early in the detailed design phase to modularize the major electrical substations and distribution centers to avoid the complexity and delay of traditional construction. Although transport arrangements were extremely complex, the substations and equipment rooms arrived with switchgear and equipment already installed, thus reducing the requirement for additional highly skilled personnel at the site.

Schedule Performance

Detailed logistical planning is required to meet schedule requirements for work at Tengiz since the nearest seaport capable of handling major pieces of equipment is over 400 miles away and not usable from November through May, when rivers and canals feeding the Caspian Sea freeze over. Despite the weather conditions and the remote location of the work, we have met every schedule requirement for the projects we have done at Tengiz.

Bechtel has mobilized and sustained a project team of as many as 3,000 non-manual and manual personnel at Tengiz. The team is composed primarily of Turkish, Kazakh, and U.S./U.K. personnel. To mobilize project personnel to Tengiz to meet project schedules, we established a charter flight directly between Istanbul and the site. During peak mobilization periods, the charter operates weekly. Since all foreign nationals working in Kazakhstan are required to have a valid Foreign Workers license, we set up a Government Affairs department whose main function is to obtain these licenses for all foreign nationals.

Customer Satisfaction

Perhaps the best indication of customer satisfaction has been the steady expansion of our scope of responsibilities over the past 14 years, which can be attributed to our experience, excellent past performance, and outstanding safety and local content records. The initial contract for maintenance and repair of existing infrastructure outside the oil and gas plant has grown into a multidisciplinary contract, including engineering, procurement, and construction of new processing facilities.

Bechtel has completed our major project work on schedule and within budget, helped TCO to deal with difficult labor and permitting issues, and effectively supported their efforts to improve their standing in the local and regional community.

Abu Dhabi Polymers Company Ltd. (Borouge)
Borouge Petrochemicals Project, Abu Dhabi
1998-2002

The Borouge Petrochemicals Project demonstrates Bechtel's ability to meet aggressive schedule goals while executing a high-quality, safe project in a logistically challenging desert location. The project included:

a 600,000-ton-per-year grassroots ethylene plant;

pretreatment units to remove trace components, such as mercury and arsine from the ethane and propane feed;

a butane-1 unit;

a hydrogen purification unit;

a central control building;

a main electrical substation;

various other buildings and utilities; and

external interconnects to the Ruwais Industrial Complex in western Abu Dhabi.

Project Scope

Bechtel, together with alliance partner Linde A.G. of Germany, performed full engineering, procurement, and construction; commissioning; and startup services for the export terminal. Subcontracts were established for construction activities with Bechtel maintaining overall management and control. The project also will increase the capacity of the ethylene boil-off recovery system, construct four kilometers (2.5 miles) of transfer lines to an existing jetty, and install the loading and unloading arm and control room on the jetty.

Cost Performance

This was a lump-sum contract requiring extremely tight controls and constant management review to ensure that the project team stayed within budget. Bechtel implemented its proven project controls system, reporting procedures, and processes to maintain effective control throughout the project. During the project, the construction team identified a need to collate progress data that could be used to measure productivity. We developed a quantity unit rate report specifically for the project and used it to identify deficiencies so that timely corrective action could be taken.

Schedule Performance

Early in the project, we recognized that we would have to accelerate the completion of the cracked gas compressor system in order to meet the aggressive project schedule goals. By assigning a dedicated engineering and construction team and using good system definition, model reviews for the entire team, and night shift work, we were able to complete this critical system and put it into operation early in the construction phase. Once completed, the compressor was set to run on air rather than ethylene and used to blow out all the downstream process piping, much of which was large-bore and required large volumes of air. The compressor was then used for pressurizing and leak-testing the process systems. As a result, we had very few startup delays due to leaks at the piping flanges during cool down of the cold train.

Halfway through the project, the customer awarded us a major portion of additional work, which included the addition of an ethylene export facility and external interconnects. The team was able to integrate the new scope into the existing execution plan without impacting the overall schedule. In order to achieve mechanical completion of systems critical to the commissioning and startup schedule, we implemented a full night shift during the first half of 2001 to take advantage of the cooler climate at that time of the year.

We successfully met the shortest project schedule ever for an ethylene plant. A set of very aggressive key contract milestones was established at the beginning of the project and the team successfully met each one of them. The construction team managed to achieve overall progress of 1.6 percent per week (2.2 percent per week at peak) despite harsh climatic conditions with temperatures consistently over 40° C and high levels of humidity.

Safety Performance

Bechtel implemented a very successful zero-accident program on the project and achieved one of the best safety records ever seen in the region. At one point, we worked more than 13 million job hours over an 11-month period without a lost-time accident. Overall, the incident rate for the project was 0.07. As a result, the project received the 5th Annual ADNOC Health, Safety, and Environmental (HSE) Award for outstanding achievement by individuals and teams, commitment to HSE, and best practice and business know-how. In 2001 we received Abu Dhabi National Oil Company's Health, Safety, and Environment Performance Award, in recognition of the safe performance record at the Borouge Petrochemicals Complex. The award recognizes outstanding achievement by individuals and teams from across the ADNOC group of companies.

Customer Satisfaction

Bechtel met all project milestones and delivered the completed project on schedule and under budget. Bechtel gave Borouge a quality plant that exceeded their performance expectations while meeting an extremely aggressive schedule and achieving one of the best safety records in the region.

Bechtel met a very tight schedule while giving the customer a high-quality plant that is producing beyond their original expectations. The customer demonstrated its confidence in our project team's performance by awarding $50 million of additional scope on a change order basis instead of seeking competitive bids.

2.9.1.1 Capability to Follow A Detailed Work Plan And Schedule

2.9.1.1(a) Schedule Development

The function of schedule and schedule control falls under the responsibility of the project controls manager. Bechtel's scheduling and scheduling control system is based on a blend of computerized networks, control logs, and graphs that are organized into a schedule hierarchy. Schedules are developed for the overall project and for each facility.

Project schedule basis and qualifications are documented and distributed with the issue of the detailed schedule by project controls. Revisions are prepared and distributed, as required, with schedule updates and revisions if the basis and qualifications change during the project.

Project schedules are prepared using the critical path method ("**CPM**") technique and precedence diagram method format. The latest version of Primavera P5 Enterprise software is used. All CPM schedules are resource loaded with engineering and construction job hours in order to provide staffing curves, quantity histograms, and progress charts to validate schedule viability during the development of the detailed schedule.

The schedule development and control plan and project execution summary schedule (Level 1) is typically issued with in 60 days of contract award.

The development of the detailed schedule is driven by the start-up schedule. Planning and execution will follow the needs required to engineer, procure, and construct the facility in a manner that will allow construction to complete the critical areas in a timely and efficient way to support the startup schedule. External constraints, such as weather, labor availability, etc., will be factored into the basis and noted as appropriate.

The detailed execution schedule is typically issued within 180 days of contract award.

Once the schedule is issued for control, the engineering progress and performance ("EPP") data will be maintained using the EPP module of EPCWorks.

Project schedules at all levels of the schedule hierarchy will relate to each other in a dynamic environment in order to efficiently and correctly reflect schedule information at each defined level. Consequently, information that does not reside in the P5 database is structured in such a manner that logical groupings of detail information (i.e., EPP and the procurement tracking system) can be easily summarized or rolled-up to corresponding activities in the CPM network. Conversely, activities in the CPM schedule are structured to correspond to the logical groupings of activities or deliverables in lower level schedules.

2.9.1.1(b) Schedule Control

Bechtel's approach is designed so that planning takes place before schedules are developed. The entire project team participates in the planning process. The process includes scope review and definition, material lead-time review, and integration of the plan with the overall project schedule. The schedule is reviewed with the responsible parties again to ensure full and complete buy-in of the project team.

Schedule control uses a hierarchical, integrated system of computerized and manual scheduling techniques to assist the project team in developing a valid performance plan. Activity logic integration is accomplished through the work breakdown structure and judicious use of activity ID and activity code structure features provided by the Primavera P5 software. The schedules start at the milestone level for overall project management and cascade down with sufficient details to project punchlists. Summary and detail level schedules are used to integrate all the activities on the project. The schedules provide sufficient detail to identify the specific requirements and responsibilities to achieve key target dates.

Schedules are monitored, reviewed, and updated on a regular basis. This process allows revisions to be made reflecting changed logical approaches as necessitated by conditions or directed by management. Problems that affect or have a probability of affecting the schedule are placed on a critical items list that indicates the responsible persons for action and defines the recovery action to be implemented.

Once the initial CPM schedule is developed, resource loaded, calculated, and leveled, it is reviewed and approved by the project team. The approved schedule constitutes the project's schedule baseline. Progress, scope changes, current schedules, etc., are all measured against this baseline. The approved baseline schedule is preserved as a target schedule and is not to be changed without appropriate approvals.

2.9.1.1(c) Engineering/Procurement Status

The Level III detail engineering and procurement schedule reflects the engineering and procurement deliverables on the project. The schedule is prepared using Primavera and is updated on a routine basis.

Schedule control of design development and detailed design phases of the work is achieved using ePCWorks. Design documents, drawings, material requisitions, and specifications are tracked in relation to predetermined control points. Control points are normally measurable and quantifiable points such as issue for review or issue for bid. The control points are given a weighted value. This forms the basis for physical progress measurement of engineering/ procurement deliverables and provides the status.

2.9.1.1(d) Construction Status

The Level III detail construction schedule will be resource loaded with job hours and physical quantities of work using Primavera. Manpower and quantity histograms and progress curves are generated from the P5 database to validate schedule viability. The quantity installation and manpower curves and histograms are charted and visible to the construction team and owner at the site. Reporting of quantities is achieved using Bechtel's proprietary program ePCWorks to track major quantities installed. A four-week rolling schedule is produced using the Level III schedule information to focus on planned work.

To manage the activities of the individual pipe-laying equipment spreads, a March Chart for each spread will also be developed and maintained to provide the progress on geotech, ROW, grade and winter road build, pipe laying, welding and coat, string, bend, ditch, lower-in, and backfill activities.

2.9.1.1(e) Subcontract Monitoring

Subcontract management at the site consists of a detailed plan from each subcontractor that includes measurable quantities of work by pay item and is used to measure contractor progress against the schedule and reported weekly.

2.9.1.1(f) Critical Path(s) Determination And Analysis

The critical path(s) in a CPM network can be defined as those activities containing zero, or minimum, total float. Critical activities control the overall duration of the project.

Critical path(s) can be identified by running a tabular P5 report sorted by total float. Also, a variety of graphical schedules can be plotted with the critical path(s) highlighted by line weight, fill patterns, or pen colors. Manual identification of critical path(s) on P5 schedules is not necessary.

Critical path(s) analysis is the process of reviewing critical activities with the project team to determine ways to shorten critical activity durations or change logic ties to shorten the schedule or to confirm that adequate resources are, in fact, available and dedicated to perform critical activities.

2.9.1.1(g) Risk Reports and Contingency Analysis

From time to time, a condition may arise on the project whereby a more analytical evaluation is required in determining an estimate of the range of changes anticipated to meet an objective, whether that be cost, schedule, manpower, etc. When the need arises, project control collects the necessary data from the project team members and performs the analyses. The results are forwarded to management for review and action.

2.9.1.1(h) Scheduling and Schedule Control Methodology

The following general topics, as well as project-specific topics, may be addressed as part of qualifying the final schedule that is issued for control:

- Work breakdown structure;
- Detailed engineering / procurement schedules;
- Engineering Progress and Performance Report;
- Project milestone summary schedule; and
- Implementation plans.

This methodology is discussed in detail in the Project Execution Plan.

2.9.1.1(i) Bechtel Standard Procedures

Following is the list of key Bechtel schedule procedures that are utilized as a basis to generate project-specific procedures:

- 40P-C030-00501 Schedule Hierarchy
- 40P-C030-00502 Management Schedules
- 40P-00C-00503 Intermediate Schedule for Engineering
- 40P-C030-00516 Procurement Implementation Schedule
- 40P-00C-00504 Intermediate Schedule for Construction
- 40P-C030-00507 Engineering Implementation Schedule
- 40P-00C-00508 Field Detailed Schedules
- 40P-C030-00509 Progress and Performance Curves
- 40P-00C-00510 Subcontractors Schedules

2.9.1.1(j) Recent Experience

Please refer to the introductory segment of Section 2.9.1 above for examples of projects that demonstrate Bechtel's ability to successfully execute and deliver projects on schedule despite difficult logistics and harsh environments.

2.9.1.2 Capability to Operate Within a Cost Budget

2.9.1.2(a) Cost Control

The Bechtel project controls team administers the functions of cost control, scheduling and schedule control, financial, overview of contract and subcontract formation, and project cost estimating under a project controls manager ("**PCM**").

The PCM is a member of the project management team ("**PMT**") and, on a typical project, reports to the project manager or project director. The PCM is responsible for all aspects of cost control, trending/ change management, scheduling, cost and schedule forecasting, progress reporting, and cash flow. He manages this through the project controls teams responsible for the details of the various elements and locations.

Typically the project PCM has a PMT organization consisting of cost engineering, planning/scheduling, and estimating, plus cost engineers and planner/schedulers as necessary to produce overall project reporting and control. This core organization is responsible for providing resources to the individual execution teams; providing systems and procedural guidelines for execution of the work; and for providing overall project reporting, forecasting, and analysis. Specific control functions are provided by personnel assigned to individual plant process units or areas. These teams receive day-to-day execution direction from their respective project/area managers and are responsible for reporting, forecasting, and analyzing their respective process units.

Overall responsibility for the project controls program resides with the PCM of project controls in the PMT. He is functionally responsible for consistent application of project controls procedures and work instructions for all units/project teams.

2.9.1.2(b) Cost Estimating

The function of cost estimating is organized under a lead project estimator within the PMT. The lead project estimator is located in the engineering design office and is supported by discipline estimators as appropriate. The lead project estimator will prepare a detailed estimate plan consisting of methodology by plant area and commodity, a detail division of responsibility matrix, discipline deliverables matrix, and schedule prior to kick-off of the estimate.

The responsibilities of discipline estimators (instruments, piping, electrical, and civil/structural) include:

- Review and fully understand the scope of work;
- Review all available or conceptual specifications, plot plans, PFDs, P&IDs, line lists, etc., that affect the discipline;
- Ensure that engineering deliverables conform to the criteria as outlined in the estimate execution plan;
- Verify and analyze unit pricing information received from all sources to ensure the information is compliant with project specifications;
- Quantify, organize, and summarize material take-off and costing information in accordance with the parameters outlined in the estimate execution plan; and
- Execute estimates and incorporate specific construction experience, where applicable.

The project controls organization coordinates the preparation of all estimates based on the following guidelines:

- An estimate plan is developed addressing the responsibilities and methodology for estimating various portions of the project, including home office costs, equipment costs, bulk material costs, construction costs, temporary facility costs, shipping costs, insurance costs, etc.;

- Estimate procedure is based on AACE International Recommended Practice No. 18R-97, "Cost Estimate Classification System – As applied in Engineering, Procurement, and Construction for the Process Industries"; and
- An estimate kick-off meeting with the project team members is conducted to reach an understanding of the purpose of each estimate and acceptance of the estimate plan by all team members.

The driving factor of estimating is to mitigate the impact of any changes that do not add to the project's economics.

The cost control and cost estimating methodology is discussed in detail in the Project Execution Plan.

Bechtel Standard Procedures: The following list of Bechtel project set-up, cost control, estimating, and change control procedures will be utilized as a basis to generate project-specific procedures.

- 40P-C030-00101 – Cost and Schedule Integration
- 40P-00C-00201 – Proposal Preparation
- 40P-C030-00202 – Project Controls Plan
- 40P-C030-00203 – Information Technology Plan
- 40P-C030-00204 – Proposal Schedules Procedure
- 40P-C030-00205 – PC Cost Tools Setup
- 40P-C030-00301 – Cost Estimating
- 40P-C030-00303 – Estimating Classifications
- 40P-C030-00311 – Estimate Planning
- 40P-C030-00312 – Construction Cost Estimating
- 40P-C030-00313 – Services Cost Estimating
- 40P-C030-00314 – Escalation Analysis
- 40P-C030-00315 – Contingency Analysis
- 40P-C030-00316 – Estimate Presentations
- 40P-C030-00317 – Estimate Reconciliations
- 40P-C030-00318 – Estimate Review and Approvals
- 40P-C030-00321 – Estimate Budget Conversion
- 40P-C030-00401 – Budget Control
- 40P-00C-00402 – Scope Change Control
- 40P-C030-00403 – Non-Manual Job Hour and Cost Control and Performance Measurement
- 40P-C030-00404 – Construction Distributables

- 40P-C030-00406 – Field Manual Labor Job Hour and Cost Control and Craft Performance and Progress Measurement
- 40P-C030-00407 – Material and (Sub)Contract Cost Control
- 40P-C030-00408 – Trend Program
- 40P-C030-00409 – Forecasting Procedure
- 40P-C030-00410– Quantity Tracking
- 40P-C030-00411 – Standard Project Code of Accounts
- 40P-C030-00412 – Backcharges
- 40P-C030-00413 – Cost Contingency Management
- 40P-C030-00414 – Project Controls Interface with Controller Systems
- 40P-C030-00415 – Subcontract Monitoring, Administration and Progress Measurement
- 40P-C030-00416 – Insurance Claims

2.9.1.2(c) Recent Experience

Please refer to the introductory segment of Section 2.9.1 above for examples of projects that demonstrate Bechtel's ability to execute projects while maintaining effective cost control throughout and deliver it within the approved budget.

2.9.2 Mitsui O.S.K Lines (MOL)

MOL is a global leader in marine transportation and has the largest tanker fleet in the world, including crude carriers, product carriers, LNG carriers, LPG carriers and methanol carriers. MOL is a leader in LNG transportation for LNG projects worldwide. MOL and its group of companies own and/or participate in 80 LNG vessels (including 21 vessels under construction), which represents approximately a quarter of the world's existing (or under construction) LNG vessels.

MOL has 45 years of experience in the LPG tanker business and was the first owner of a fully refrigerated LPG carrier in the world. MOL's is an owner and operator of five VLGCs, or are LPG tankers with a capacity in excess of 70,000 m^3, one mid-size ammonia carrier and one pressurized LPG carrier. MOL is the operator of an additional three VLGCs and has a further ten LPG and ammonia carriers under its management.

Further information on MOL's experience and track record in the LNG and LPG shipping industry is provided in Appendices K and M.

2.10 Project Viability

2.10.1 Economic Viability

This section provides an analysis of the economic viability of the Project. The analysis is organized as follows:

- Section 2.10.1.1 describes the targeted primary markets for LNG and NGL.
- Section 2.10.1.2 describes the estimated Project costs and third party costs for transportation, liquefaction, and processing services for the Project's components.
- Section 2.10.1.3 provides a projection of wellhead netback revenues to the North Slope producers, based on: (a) the estimated gross revenues from gas and NGL sales in the target markets; less (b) estimated costs of transportation and processing.
- Section 2.10.1.4 provides a projection of cash flows to the State of Alaska and the U.S. federal government, based on projected government revenues from taxes and royalties.
- Section 2.10.1.5 provides an analysis of the competitive position of the Project relative to proposed other Alaska gas transportation projects.

2.10.1.1 Target Markets for LNG and NGL

At present, markets in East Asia, specifically Japan, Korea and Taiwan, appear to be the most attractive in the Pacific Basin in terms of both prices and market depth. Therefore, the economic viability analysis in this Section 2.10 of the Application is based on the assumption that natural gas liquefied at the facility in Valdez will be transported to and sold to consumers in East Asia.

The Port Authority has been approached by experienced gas marketing companies, who have expressed interest in purchasing LNG and NGL on a free-on-board (**"FOB"**) basis in Valdez and marketing such LNG and NGL to consumers in the Pacific Rim markets.

The Port Authority has designed the commercial structure of its Project to maintain the flexibility to offer transportation and liquefaction services to third party shippers (including North Slope producers of natural gas) who may desire to maintain ownership and marketing control of the LNG and NGL produced at Valdez. In such a scenario, as the Port Authority and its Project partners will not have control over the ultimate destination of the LNG and NGL, the responsibility for selection of destination markets, transportation and marketing will belong to such third party shippers of natural gas. However, for the purposes of the analysis in this Section 2.10, it has been assumed that such third party shippers would seek to maximize sales prices and netback profits and, therefore, would seek to market their LNG and NGL in the most attractive markets available to them. Based on current market conditions, this would imply that the targeted markets would be in East Asia.

The sections below provide a description of the characteristics of the LNG markets in East Asia, including projected supply and demand, price-setting mechanisms, and projected market prices.

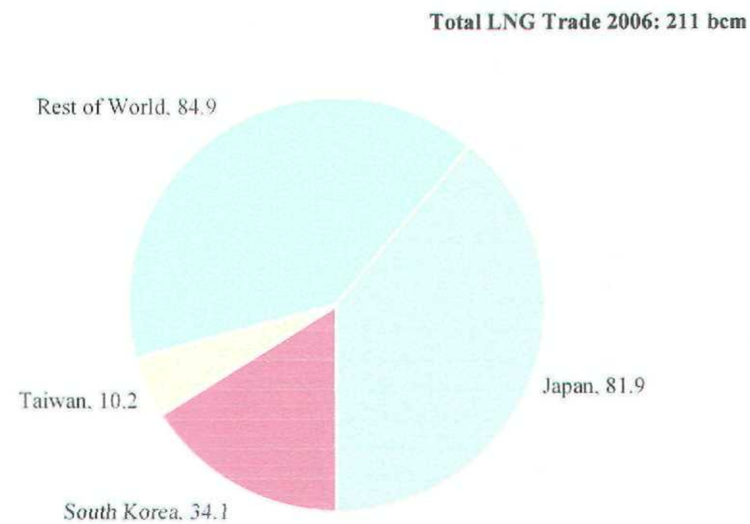
2.10.1.1(a) East Asian LNG Markets: Demand and Supply

The East Asian market for LNG, comprising Japan, South Korea and Taiwan, has been the largest regional market for decades. In 2006, the total amount of LNG traded internationally was the equivalent of 211 billion cubic meters (**"bcm"**) of natural gas,[9]

[9] BP Statistical Review of World Energy June 2007.

approximately equal to 154 mmta of LNG. Of this total, the combined LNG imports Japan, Korea, as shown in Figure 19 below, represented 60% of total LNG trade in 2006.[10]

Figure 19 Global LNG Imports 2006 (bcm)



Source: BP Statistical Review of World Energy June 2007.

Japan is the single largest country importer of LNG in the world. As shown in Figure 19 above, Japan imported 81.9 bcm of LNG in 2006 (or approximately 60 mmta of LNG), accounting for 39% of global LNG imports for the year.[11] South Korea is the second largest country importer of LNG, with approximately 16% of worldwide imports. Taiwan accounts for approximately 5% of world LNG imports.

In addition to the established East Asian LNG importers of Japan, South Korea and Taiwan, China has recently begun importing relatively small amounts of LNG. While China is expected to grow as an LNG buyer, the level of Chinese demand in the future is uncertain. China has not been included as a base case target market for LNG in this analysis.

Global demand for LNG market is projected to grow substantially over the next 25 years. The forecast global demand growth for 2010 is between 198 mmta and 227 mmta in 2010, for an increase of 29-47% over 2006 levels.[12] Demand in 2020 is projected to

[10] Id.

[11] Id.

[12] Source: The Institute of Energy Economics, Japan. "Natural Gas and LNG Supply/Demand Trends in Asia Pacific and Atlantic Markets (2006), September 2007.

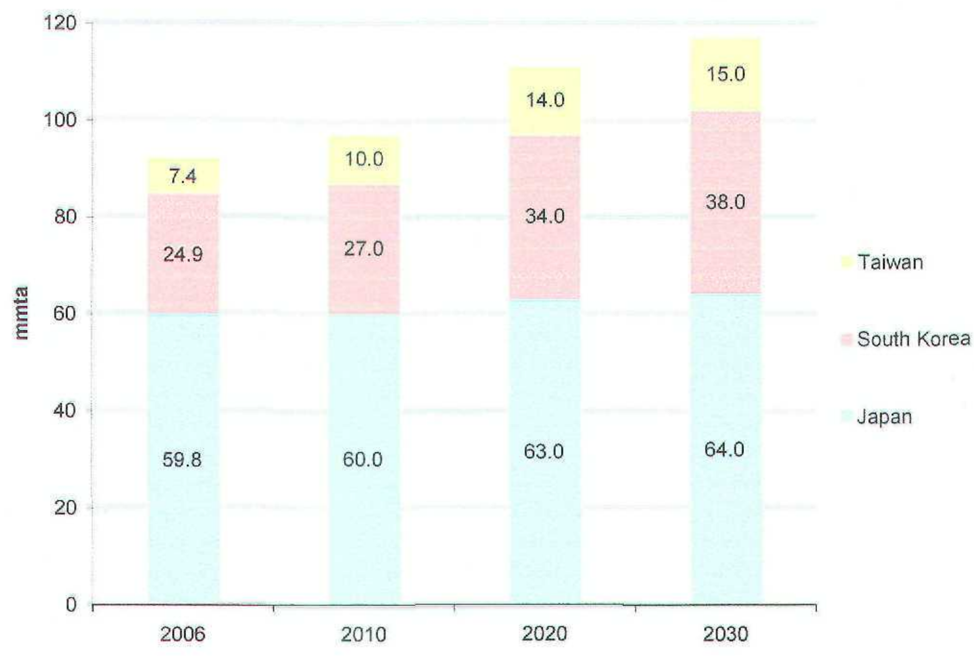
grow to 350-376 mmta by 2020 and to 379-509 mmta by 2030, or an increase to roughly three times the current size of the market.

While LNG demand in the Atlantic basin is expected to grow rapidly, particularly as the U.S. continues to import a significant portion of its natural gas consumption in the form of LNG, demand growth in the Pacific basin is also projected to grow substantially.

Based on projections from IEEJ, the combined demand for LNG from the three major current markets, Japan, South Korea and Taiwan is forecast to grow from a 2006 level of 92 mmta in 2006 to between 111 mmta and 129 mmta by 2020 under IEEJ's "low growth" and "high growth" forecast scenarios, respectively.

Figure 20 below shows forecast demand from the three countries for 2010, 2020 and 2030 under the "low growth" scenario. Figure 21 shows forecast demand for the same time frame under the "high growth" scenario.

Figure 20 LNG Demand Growth in East Asia (Low Growth Scenario)



Sources: IEEJ for forecast 2010 – 2030; BP Statistical Review of World Energy June 2007 for 2006 figures.

Figure 21 LNG Demand Growth in East Asia (High Growth Scenario)

Sources: IEEJ for forecast 2010 – 2030; BP Statistical Review of World Energy June 2007 for 2006 figures.

In addition to growing demand from the three established LNG importers in East Asia, China is projected to emerge as a major importer of LNG. LNG demand in China is forecast to increase from less than 1 mmta currently to 10-16 mmta by 2020 and 20-33 mmta by 2030. Due to the uncertainty associated with the development of China as a major LNG importing country, it has not been included as a base case destination market for the Project at this time.

Another development of potential significance in the Pacific basin LNG market is the forecast increase in demand for LNG from India, which would open additional supply opportunities for both Pacific and Middle Eastern suppliers of LNG.

The Pacific basin LNG market has also been affected by the decline of LNG exports from Indonesia's Arun and Bontang liquefaction plants due to steadily dwindling production from aging gas fields, coupled with increased diversion of gas production to satisfy local demand.

2.10.1.1(b) Price-Setting Mechanisms in the East Asian LNG Markets

Traditionally, most LNG traded in the East Asian market has been purchased on a bilateral basis under long-term contracts extending over twenty or more years. Although the general characteristics of the pricing provisions in these contracts are known, most LNG sales and purchase agreements are generally treated as confidential commercial arrangements, with the details of specific pricing and other provisions typically not available to the public.

At each point in time, East Asian buyers are purchasing LNG under a multitude of different long-term supply contracts, each of them executed under specific market conditions at the time of the agreement between the individual buyer and supplier. As market conditions change over time and the individual circumstances of specific buyers and sellers vary, it would not be unusual, at a given point in time, for buyers to be purchasing LNG under different contractual prices.

The characteristics of the East Asian LNG market described above mean that typically there is no single "market price" of LNG in the East Asian market but, rather, a potentially a number of different active supply contracts with varying price provisions. This is different than the situation in the North American natural gas marketplace, where the price discovery mechanism is more transparent and is driven by a spot market at various regional gas trading hubs.

For the purposes of the analysis in this Application, the projection of East Asian market prices for LNG is assumed to mean the contractual terms that the Project and/or other gas sellers would be expected to enter into on a long-term basis with East Asian buyers of LNG, which have been estimated on the basis of observed current market conditions and recent transactions between suppliers and buyers in Pacific Basin, as well as forecasts by other parties.

2.10.1.1(c) Oil-Indexation in Price Formulas

Customarily, LNG sales and purchase contracts with East Asian buyers have included price-indexation provisions that directly link the price of LNG to oil prices. Due to the importance of Japan as the largest buyer in the LNG market, price formulas in contracts with South Korea or Taiwanese buyers have tended to follow the model of the Japanese LNG contracts by establishing the price of LNG as a function of the Japan Crude Cocktail price ("**JCC**") of a basket of crude oils imported into Japan.

Historically, the JCC-indexed price formulas used in Japanese supply contracts have had the following formulation:

$$P = A * JCC + B$$

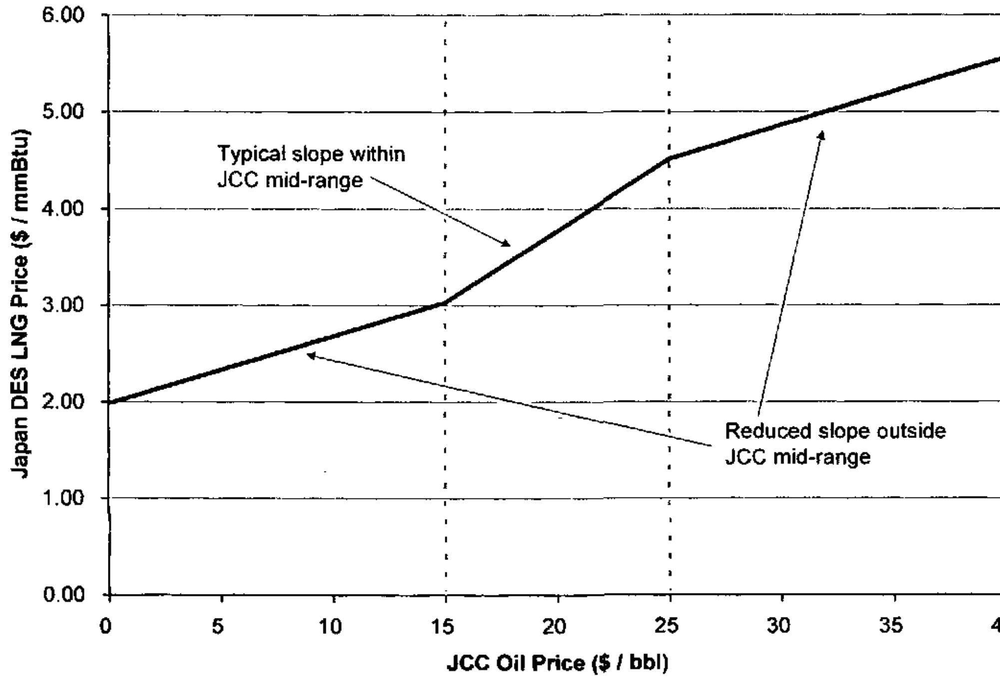
where:

P is the price of LNG (in cents per mmBtu) in Japan on a DES basis; the slope A in the past has often been 14.85 or similar; and the intercept B – a number between 70 and 90.

The basic formula above would apply in the mid-range of "expected" oil prices, which in the past (during periods of significantly lower oil prices) has been in the range between $15 and $25 per bbl. Outside of this range, the formulas have typically been modified applying the so-called "S-curve" which reduces the slope of the curve by about half. The intent behind this S-curve "flattening" of the slope is that for prices exceeding the band of expected long-term prices, the price relationship is changed such that in periods of very high oil prices the buyer benefits from reduced LNG prices in relative terms to oil, and in periods of very low prices the seller benefits from increased prices relative to oil.

Figure 22 below illustrates graphically the relationship between JCC oil prices and the LNG prices for supply to Japan on a DES basis that has been used in long term contracts in the past.

Figure 22 Historical Japan DES LNG "S-Curve" Formula



Source: Alaska Gasline Port Authority Financial Model

In recent years, market developments have put an upwards pressure on the historical LNG formula. Suppliers have been in a favorable position since about 2005, as the Pacific basin market has moved to a position of expected supply shortages,[13] which has been due to a number of factors, including growing demand and delays in several Pacific basin LNG projects in development.

This has resulted in pressure on buyers to revise the traditional LNG pricing formulas to achieve higher prices, including by reducing or eliminating the S-curve "flattening" of the price curves and increasing the slope in the formula.

Based on publicly available market reports, recent Australian Northwest Shelf supply arrangements have significantly increased sales prices by revising the slope in the formula upwards.[14] More recently, Kogas, the South Korean natural gas utility, has reportedly agreed to purchase LNG from Qatar using an even more seller-friendly price

[13] See, for example, "S Korea faces LNG shortage of up to 4 mil mt/yr during 2007-2012," Platts Energy Bulletin, Oct 18, 2006.

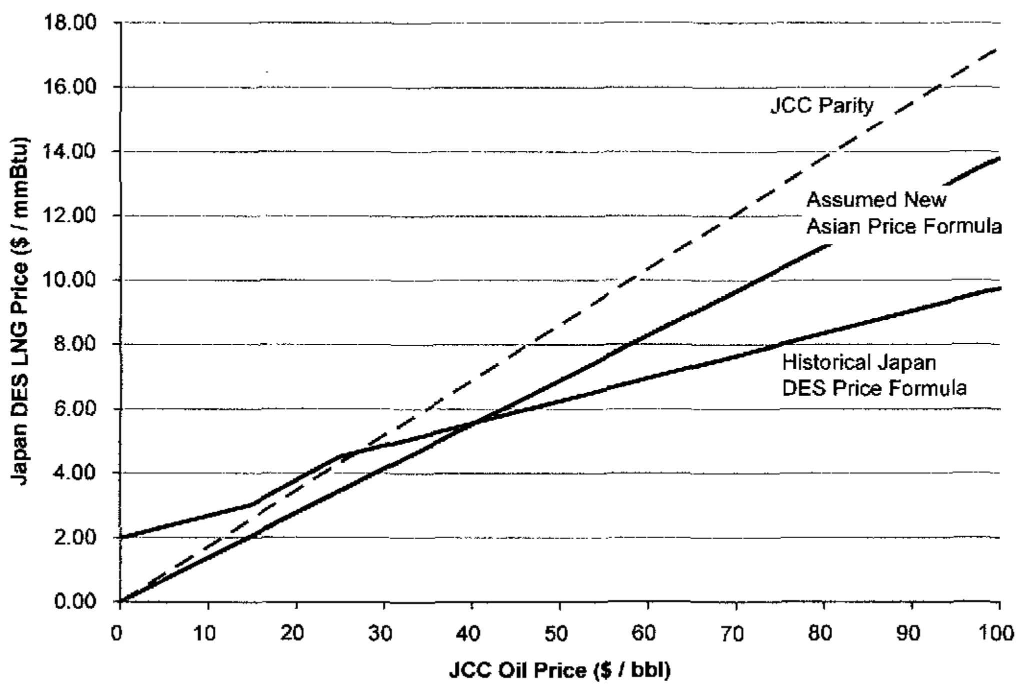
[14] See, for example, *http://www.fgenergy.com/AOGC-2007.pdf* and *http://www.oilsearch.com/resource/2007%20Investor%20Field%20Trip%20-%20%20GAS.pdf*

formula, based on a price relationship between crude oil and LNG close to thermal value parity.[15]

These new pricing arrangements, under recent high oil prices, result in LNG prices that are significantly higher than what the LNG prices would have been using the traditional Japan DES S-curve formulas. For the purposes of the analysis in this Application, it has been conservatively assumed that the currently exceptionally strong position of sellers in the Pacific basin would not be sustained in the longer term, resulting in a somewhat eased pressure on LNG buyers in the region.

To formulate an assumed relationship between JCC and East Asian LNG prices that is more conservative than the recently observed highly seller-friendly price formulas near parity with crude oil, yet reflects the stronger market conditions reflected in the revision of the customary historical price relationships, it has been assumed that LNG prices would be 80 percent of JCC on a thermal equivalency basis. This assumed relationship between JCC prices and LNG prices is graphically represented in Figure 23 below, and is compared to the historical price formulation used in the past, as well as with the parity curve, which approximately represents certain recent market transactions.

Figure 23 Assumed East Asian DES Price Formula for LNG



Source: Alaska Gasline Port Authority Financial Model

The above assumption used in this economic analysis is consistent with the price forecast for Asian LNG by IEEJ, in which it is projected that Asian LNG prices would be in the range between 80 percent and 90 percent of JCC.

[15] Id.

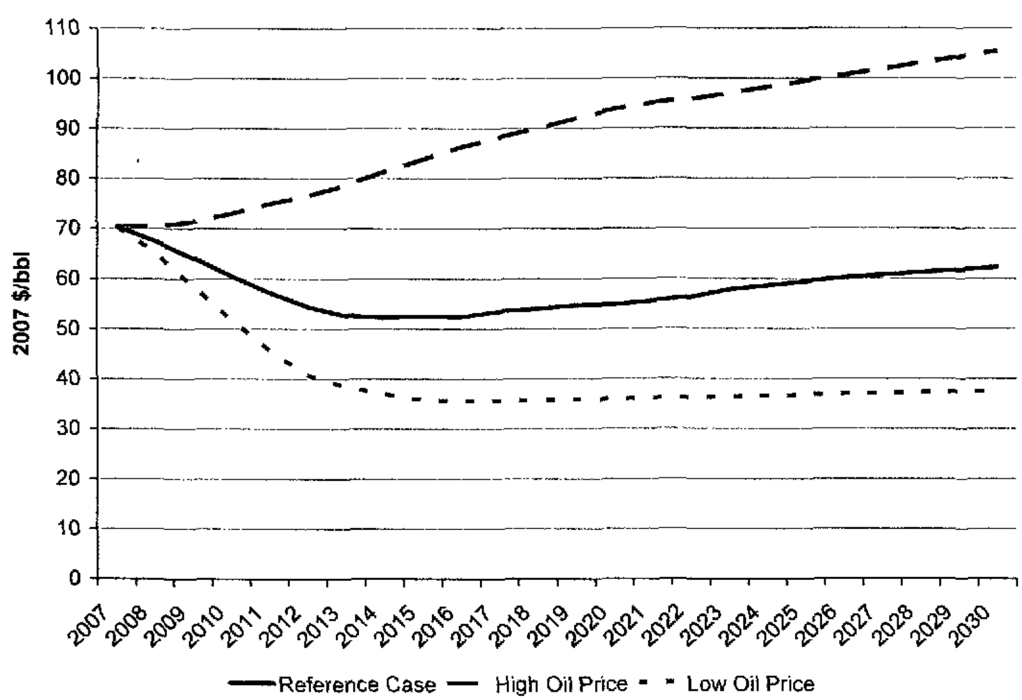
2.10.1.1(d) LNG Price Assumption Series

The assumed contractual LNG price formula described in the preceding section establishes the relationship between oil prices and the LNG sales prices. The actual assumption for LNG prices used analysis in this Application is determined by the assumption for oil prices.

The RFA specifies that the assumed oil price in the Application is to be benchmarked off the price forecast for imported crude oil in the DOE's Energy Information Administration ("**EIA**") most recent Annual Energy Outlook publication. EIA provides oil and natural gas price forecasts for three price levels: (1) reference case; (2) high prices; and (3) low prices. EIA provides its forecast in constant 2005 dollars. For the purpose of consistency across the analysis in this Application, an inflation adjustment has been applied to the EIA price forecasts to express such prices in 2007 terms.

Figure 24 below shows the EIA price forecast at each of the three price levels, as provided in the EIA Annual Energy Outlook 2007 and adjusted for inflation from 2005 to 2007.

Figure 24 EIA Price Forecast for Imported Crude Oil (2007 dollars)

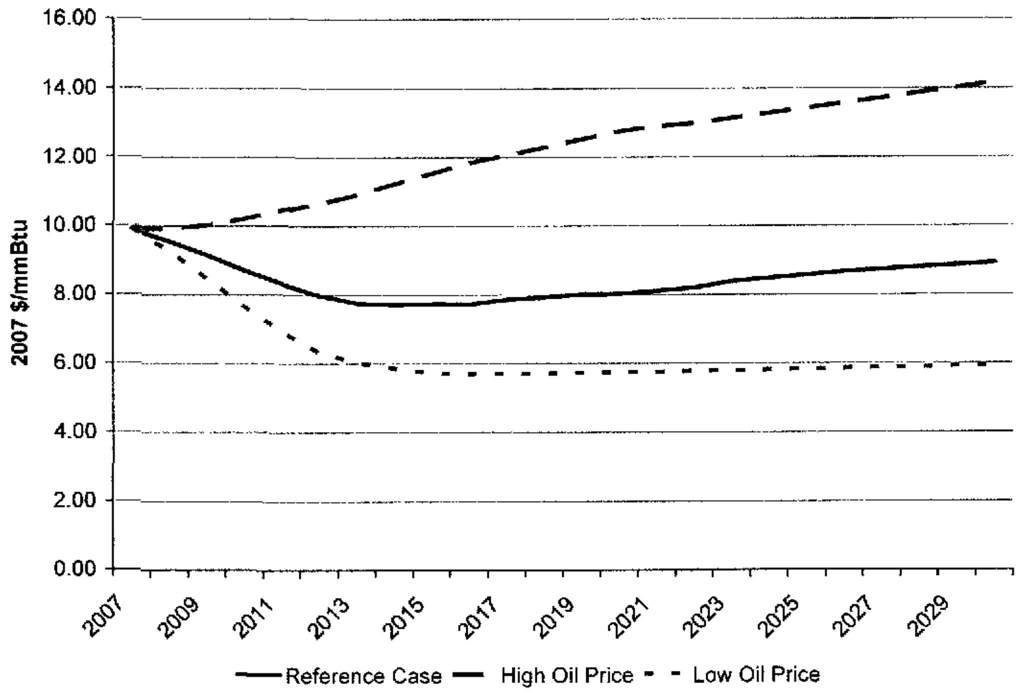


Source: EIA Annual Energy Outlook 2007

Based on the above three oil price scenarios and using the assumed formulaic relationship between the JCC oil price and East Asian LNG prices, as described in Section 2.10.1.1(b) and illustrated in Figure 23 above, a forecast of LNG sales prices has been prepared that corresponds to each of the three oil price scenarios (reference case, high price and low price) in EIA's Annual Energy Outlook 2007.[16]

Figure 25 below shows the assumed LNG prices in East Asia (on a DES basis), projected on the basis of EIA's oil price forecast that have been used for the purposes of the analysis in this application.

Figure 25 Assumed E. Asian LNG Prices (based on EIA oil price forecast)

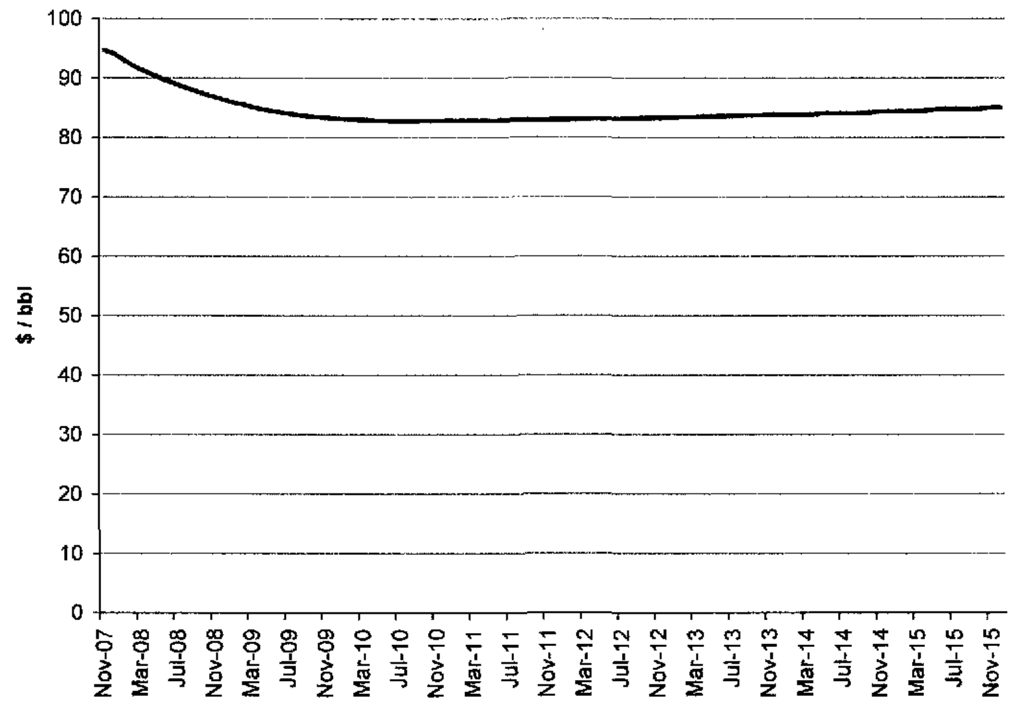


Source: Alaska Gasline Port Authority Financial Model

The Base Case projections used in the economic viability analysis in this Application assume that oil prices correspond to the Reference Case forecast provided in EIA's Annual Energy Outlook 2007. However, EIA's High Oil Price scenario more closely resembles recentl market oil prices. As shown in Figure 26 below, current oil futures prices on the New York Mercantile Exchange (**"NYMEX"**) are between $80 and $90 per bbl for contract months through the end of 2015. This corresponds closely to the EIA High Oil Price scenario forecast for the same time period.

[16] The EIA forecast for crude oil prices is expressed as the forecast weighted average price of oil imported in the U.S. The formula for East Asian LNG prices, on the other hand, links the LNG price to JCC, which is based on a different basket of crudes than the weighted average U.S. import price. The Port Authority financial model projects JCC prices as a function of the assumed average price of oil imported in the U.S on the basis of the historical relationship between the two price series.

Figure 26 NYMEX Light Sweet Crude Futures (November 19, 2007)



Source: NYMEX

As described further in Section 2.10.1.1(e) below, in a high oil price environment, similar to the current market conditions, the East Asian LNG markets present a particularly attractive target markets for monetizing Alaska gas in comparison with alternative destination markets, including North American markets accessible via an overland pipeline. For this reason, the analysis presented herein provides results based on the High Oil Price scenario developed by EIA, in addition to the Base Case results that are based on EIA's Reference Case price scenario.

2.10.1.1(e) Comparison of E. Asian LNG Markets with N. American Gas Markets

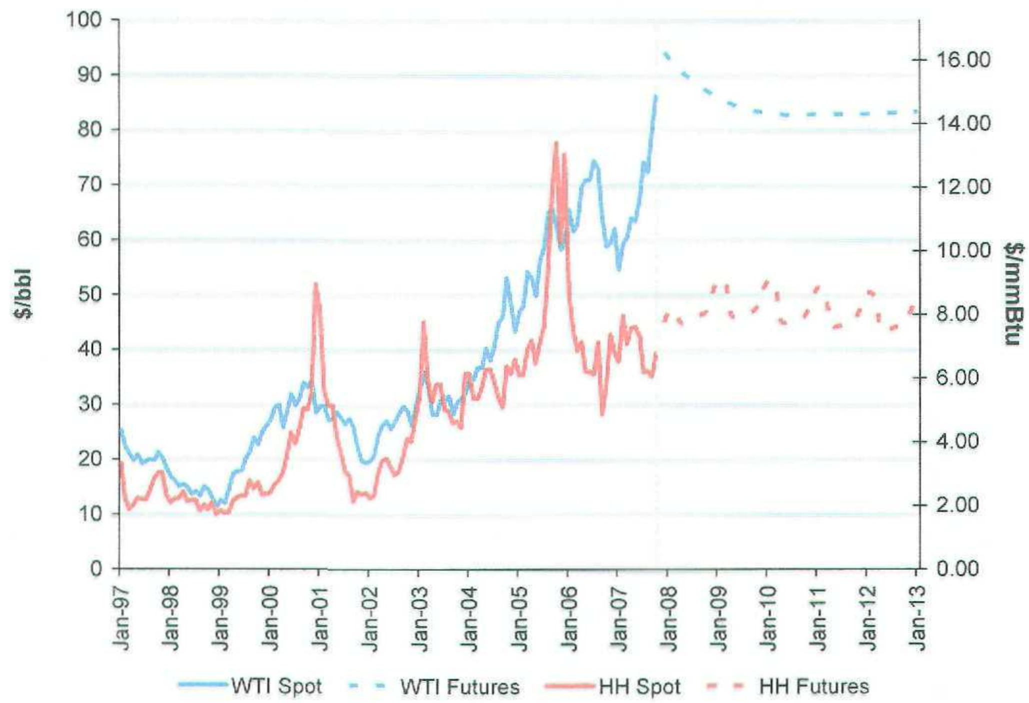
The direct contractual link between LNG prices and crude oil prices in the East Asian LNG markets contrasts with the price setting mechanism in North American gas markets, where gas prices are driven by supply and demand in localized but interconnected gas spot markets. Price formation in North America is the direct result of gas-on-gas competition. Oil prices do influence North American gas prices indirectly by having an effect on the supply and demand for natural gas. On the demand side, gas prices have often been constrained within a band defined by high-value and low-value petroleum products (distillate and residual fuel oil), due to the ability of some users to switch fuels. On the supply side, competition for exploration and production resources has prevented oil and gas prices from diverging significantly.

The historical relationship between North American oil and natural gas prices can be observed in Figure 27 below, showing Henry Hub spot prices and West Texas

Intermediate ("**WTI**") spot crude oil prices since 1997. The graph also shows recent NYMEX futures prices for months from December 2007 through January 2013.

The following key observations can be made from the graph: (a) although North American historical oil and gas prices have not been not tightly correlated, they have tended generally to move in tandem, with periods rising oil prices generally corresponding to periods of rising gas prices and *vice versa* for most of the last ten years; and (b) since roughly the middle of 2005, the price correlation appears to have weakened, with continuously rising oil prices not paired with correspondingly rising gas prices; and (c) the futures market prices natural gas for the next five years at levels substantially below futures oil prices (using a thermal equivalency factor of 5.8 mmBtu per barrel of oil).

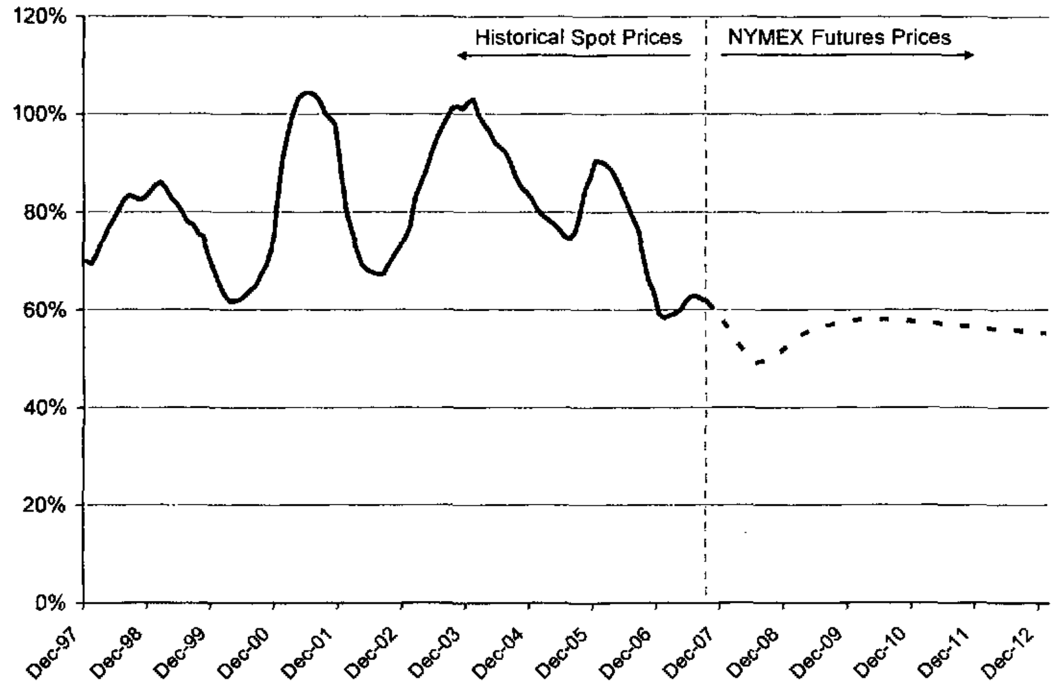
Figure 27 Historical Henry Hub and WTI Prices



Sources: Federal Reserve Bank of St. Louis Economic Research, http://research.stlouisfed.org/fred2/ *for historical spot prices; NYMEX for futures prices.*

The apparent recent "decoupling" of North American natural gas prices from continuously rising oil prices can also be illustrated by the graph in Figure 28 below, which expresses the Henry Hub prices as a percentage of oil prices, using a thermal equivalency factor of 5.8 mmBtu per barrel of oil. The relationship is shown both for historical spot prices and NYMEX futures prices. Prices are shown on a 12-month rolling average basis, to smooth out the effects of seasonal variations in natural gas prices.

Figure 28 Henry Hub Price as a Percentage of Oil Price



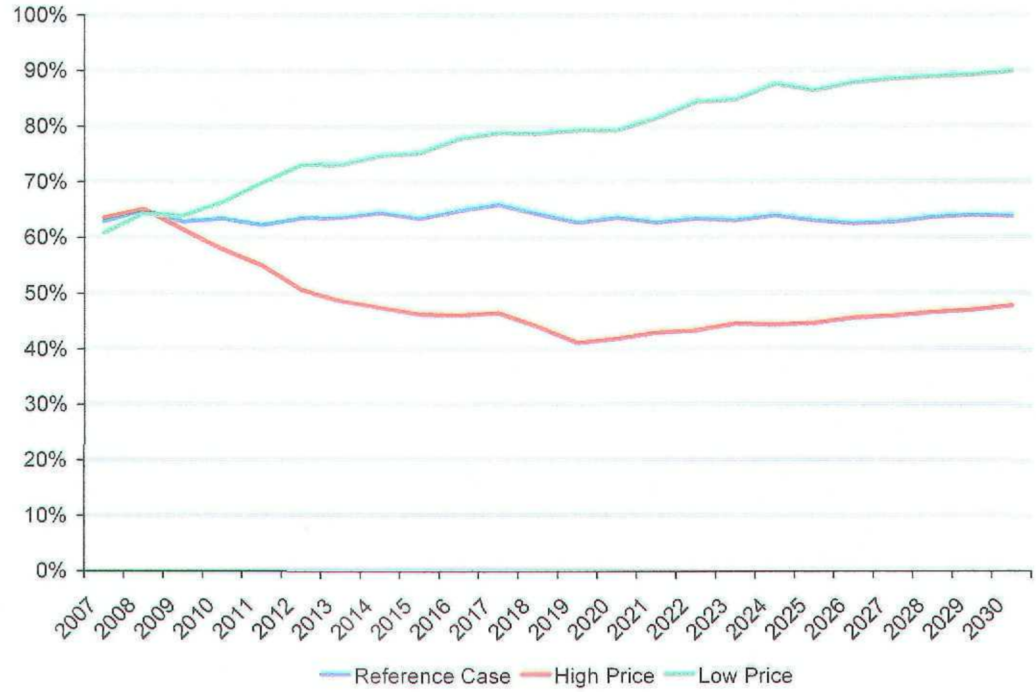
Sources: Federal Reserve Bank of St. Louis Economic Research, http://research.stlouisfed.org/fred2/ *for historical spot prices; NYMEX for futures prices.*

The graph above shows that, historically, Henry Hub spot prices have fluctuated within a band of roughly 60% to 100% of oil prices, with an average of approximately 80%. As oil prices have continued to climb during the last two years, Henry Hub prices have not increased correspondingly and have edged towards the 60% level in relative terms against oil. Prices on the NYMEX futures market indicate that Henry Hub gas prices are expected to remain below 60% of oil prices, indicating a lasting shift in the relative price relationship between oil and natural gas prices in North America, to the extent that the current high oil price environment persists.

The price forecasts in EIA's Annual Energy Outlook 2007 indicate a similar "decoupling" of the historical oil and gas price relationship in North America in the Reference Case and High Oil Price scenarios. As Figure 29 below illustrates, in the EIA Reference Case forecast, Henry Hub gas prices are projected to remain between 60% and 70% of oil prices, below the historical average during the last ten years.

In the case of EIA's High Oil Price scenario, Henry Hub gas prices and oil prices are forecast to diverge further from the historical relationship, with gas prices reduced to between 40% and 50% of oil prices, significantly below the historical levels. Only in the case of EIA's Low Oil Price scenario, gas prices are forecast to return to the historical level in relation to oil prices – with Henry Hub prices increasing from the current level of approximately 60% relative to oil up to 80-90% relative to oil for the period 2015-2030.

Figure 29 Henry Hub Price as Percentage of Oil Price (EIA forecast)

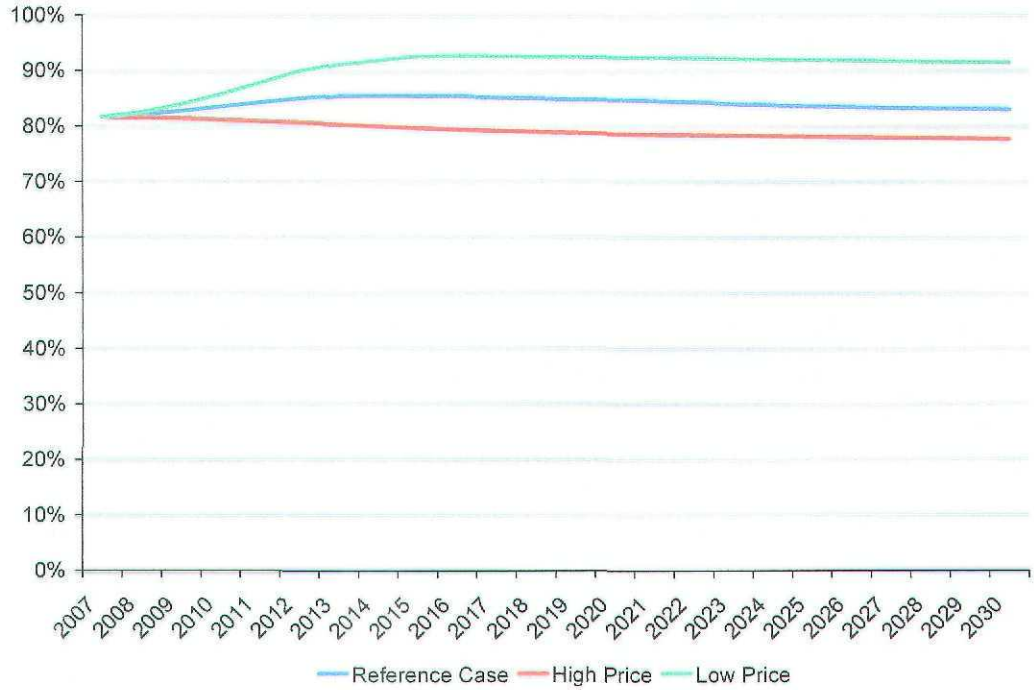


Source: EIA Annual Energy Outlook 2007.

In contrast to North American gas markets, the East Asian LNG markets would retain LNG prices that are relatively high in relation to oil prices, assuming that the JCC-indexation price formula provisions remain a central feature of Asian LNG purchase contracts. Figure 30 below shows projected East Asian LNG sales prices, expressed as a percentage of oil prices, under each of EIA's three oil price scenarios.

In all three cases, East Asian LNG prices are projected to remain at a consistently high level relative to oil. Under the High Oil Price scenario, East Asian LNG prices are projected to remain at a level of approximately 80% percent of oil prices, which is significantly higher than projected Henry Hub gas prices of between 40% and 50% of oil under that scenario.

Figure 30 Forecast E. Asian LNG prices as Percentage of Oil Price



Sources: EIA Annual Energy Outlook 2007 for forecast oil prices; Alaska Gasline Port Authority Financial Model for forecast LNG prices.

The differences in projected responses of the North American gas prices and East Asian LNG prices to different levels of oil prices show that Asian LNG prices are forecast to remain relatively higher than North American prices under EIA's Reference Case scenario. Under the High Oil Price scenario, East Asian LNG prices are forecast to be significantly more attractive from a seller's perspective than North American gas prices.

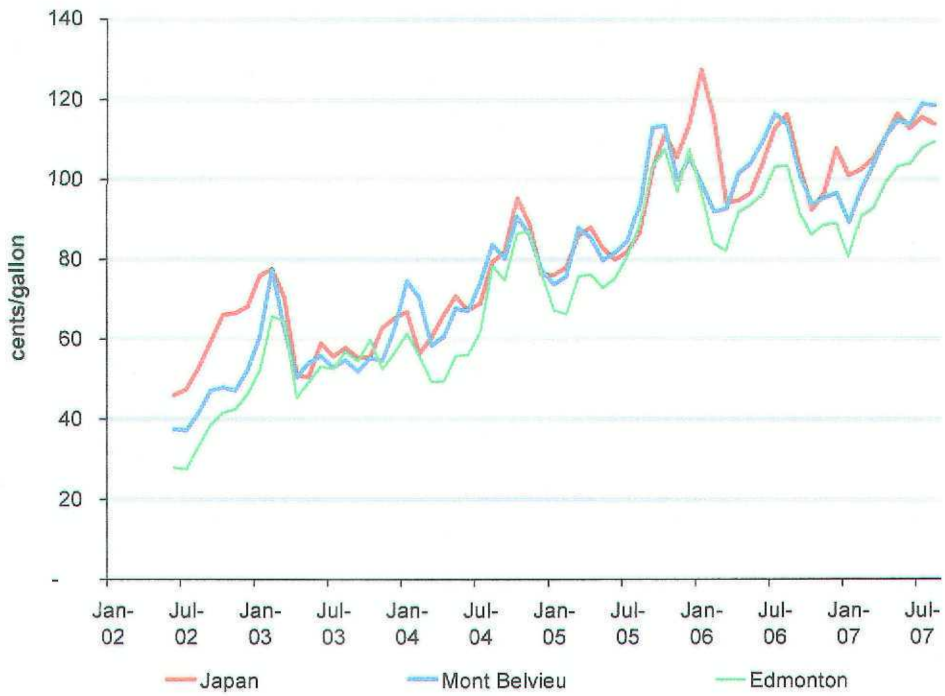
An additional advantage of the Asian LNG market is that in a high oil price environment, demand for LNG increases. Due to the features of the price indexation formulas in Asian LNG sales and purchase contracts discussed in Section 2.10.1.1(b) above, at high oil price levels LNG becomes relatively cheaper than competing oil products because most JCC indexation formulas have a slope of less thermal parity with oil.

The LNG project proposed by the Port Authority would place Alaska in a unique position to benefit from the advantages of the East Asian markets over alternative gas destination markets. Access to these LNG markets will be especially attractive for Alaska and its gas producers if the current high oil price environment persists.

2.10.1.1(f) Target LPG Markets

Like LNG, the Port Authority will retain destination flexibility with LPGs, thus improving Project economics by taking Project LPGs to the most desirable markets. Historically, LPGs in Asia have typically traded at a premium to North American markets, as indicated in Figure 31.

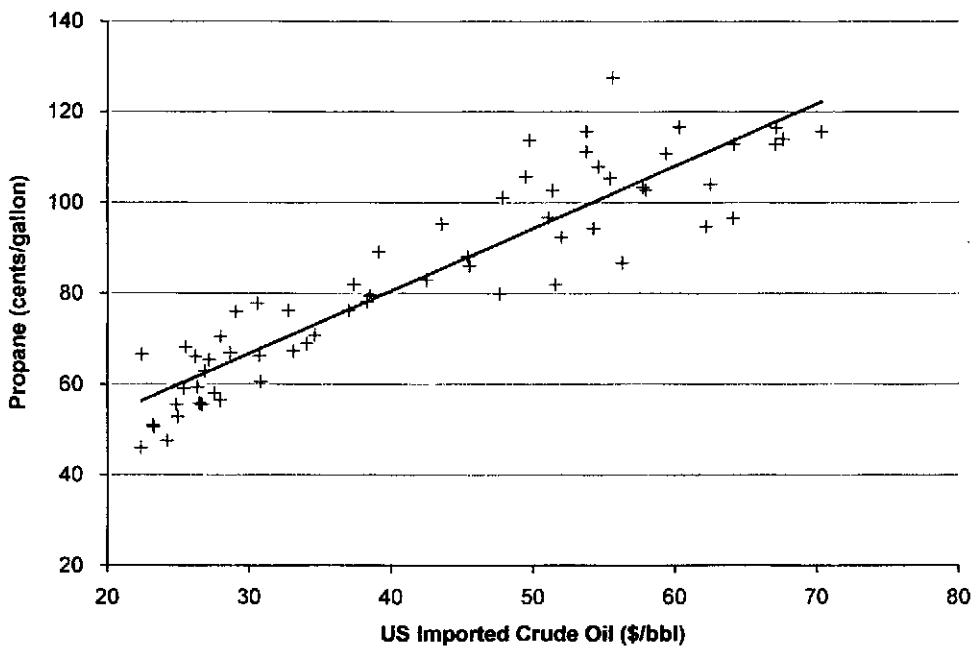
Figure 31 Historical Propane Prices



The LPG price forecasts used in the analysis are derived from the forecast Imported Crude Oil and Henry Hub price series in EIA's Annual Energy Outlook. Historical values for these prices were compared to 5-year historical propane prices in Japan, Mont Belvieu, and Edmonton, to determine the appropriate forecasting relationships using regression analysis.

Propane prices in Japan are forecast based on Imported Crude Oil prices alone. In the historical period analyzed, the linear fit had an R-square statistic of 0.85 (Figure 32), indicating a strong correlation.

Figure 32 Relationship Between Japan Propane and US Imported Crude Oil



Propane prices at Mont Belvieu and Edmonton are both forecast based on a combination of Imported Crude Oil and Henry Hub prices. These multi-variable correlations have R-square statistics greater than 0.91 for the historical data. Figure 33 and Figure 34 below show historical propane prices, prices from the correlation with Imported Crude Oil and Henry Hub, and the residuals between the historical and correlated prices.

Figure 33 Historical Mont Belvieu Propane and Correlation

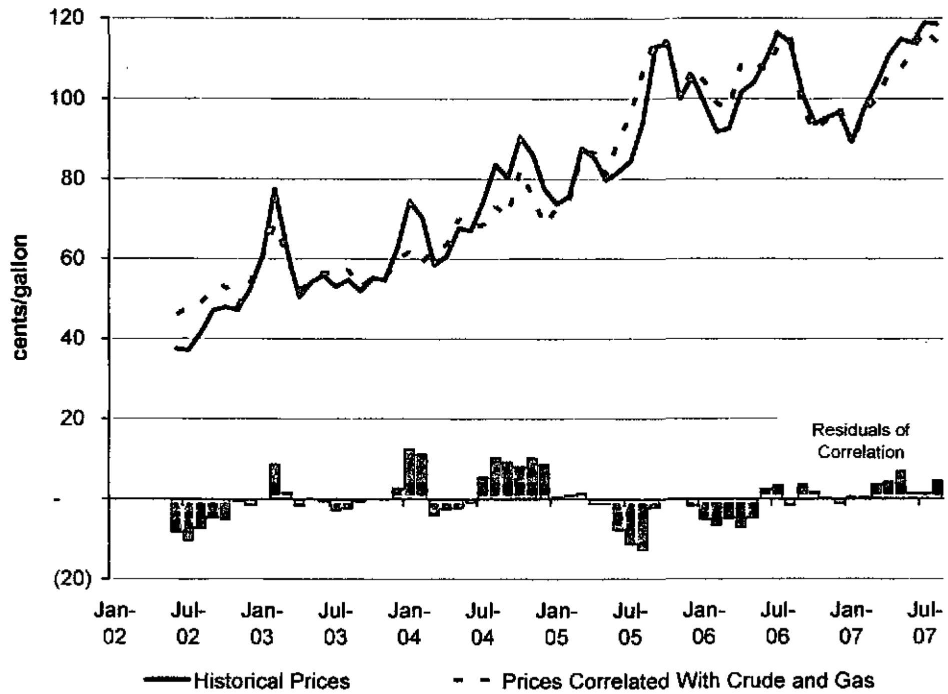
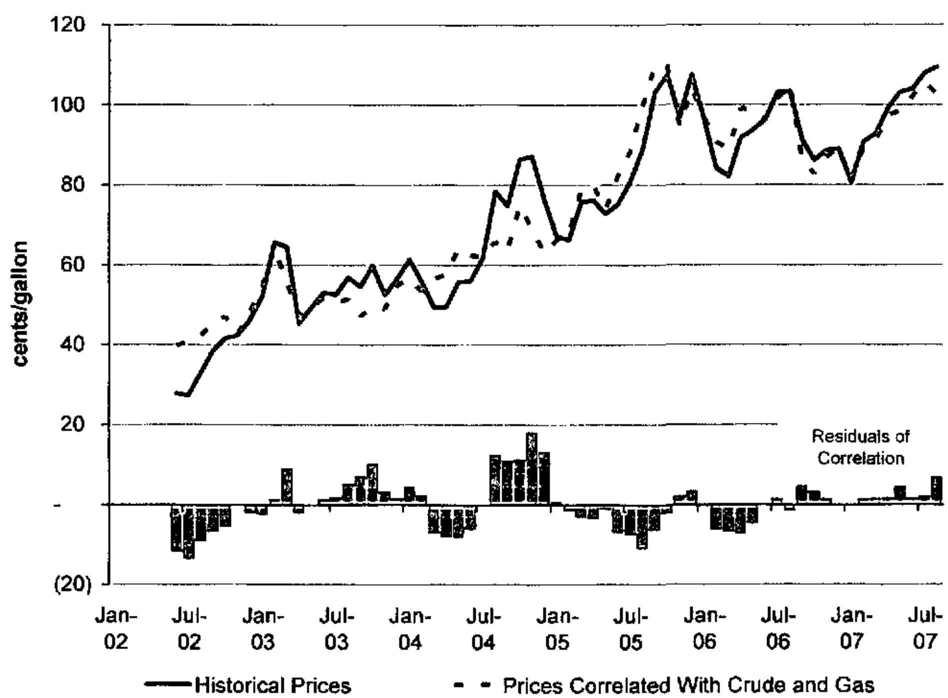


Figure 34 Historical Edmonton Propane and Correlation



Based on this analysis it is projected that LPG prices in Alberta will be at a premium to LPG prices in Canada.

2.10.1.2 Project Costs

The capital cost assumptions used in the economic viability analysis are based on the capital costs estimates developed for this application, as described in detail in Section 2.5.

Table 10 Capital Cost Assumptions

Item	Estimated Cost ($ billions)
Development Phase:	
Program Management	0.070
Pre-FEED and FEED	0.185
Surveys and Permitting Support	0.120
Regulatory Agency / Permitting Costs	0.045
Owner's Management Costs	0.105
Subtotal Development Phase:	***0.525***
Execution Phase:	
Pipeline and Compression Facilities	11.70
LNG Facilities	7.00
Owners Costs: Pipeline and LNG Facilities	4.40*
Subtotal Execution Phase:	***23.10***
TOTAL:	**23.650**

** Includes: Program management costs, escalation after 2007, owner's contingency, insurance, administrative and other owner's costs, ad valorem tax, pre-startup O&M and mobilization, linefill and licensing costs, but excludes financing costs (interest during construction, financing fees, initial funding of reserve accounts).*

In addition to the above, financing costs are estimated to be $2.2 billion.

Operating costs have been estimated to be $56 million for the Pipeline and $145 million for the LNG Facilities.

The GCP is assumed to be owned by other parties who will provide gas treatment services to the Project on a third-party basis and, therefore, the GCP has not been included in the the Project scope. However, preliminary cost estimates have been developed for the purposes of the economic viability analysis. EPC costs for the GCP are assumed to be $3.2 billion, with owners' costs estimated on a percentage of EPC cost basis. On this basis, the levelized rate of service for the GCP is estimated to be $0.73 per mmBtu of treated gas delivered to the Pipeline inlet, assuming a 75:25 debt to equity ratio.

Marine transportation services will be provided from other parties. The Port Authority has received a confidential cost estimate from the MOL Companies, which is attached in Appendix K (Confidential).

Interest rate assumptions have been based on the three-year historical average yield on the 10-year U.S. Treasury bonds, as specified under section 3.2.1 of the RFA. Cost escalation/inflation assumptions have been based on the EIA Annual Energy Outlook forecast for the Consumer All-Urban Price Index, as specified under section 3.2.1 of the RFA.

2.10.1.3 Netback Prices and Revenue

For the purpose of the analysis provided in this Application, rates of services for the Pipeline and the LNG Facilities have been projected on the basis of the cost assumptions described in the previous section. Rates for the Pipeline have been estimated using a levelized cost-of-service methodology. The assumed debt-to-equity ratio is 75:25.

In this analysis, the LNG Facility has been assumed to provide liquefaction and liquids extraction services on a tolling basis (for a detailed discussion of the anticipated LNG commercial structure, please refer to Section 2.2.3.14). A levelized toll has been calculated to set the target return on capital at 8 percent on an unlevered basis, which is.

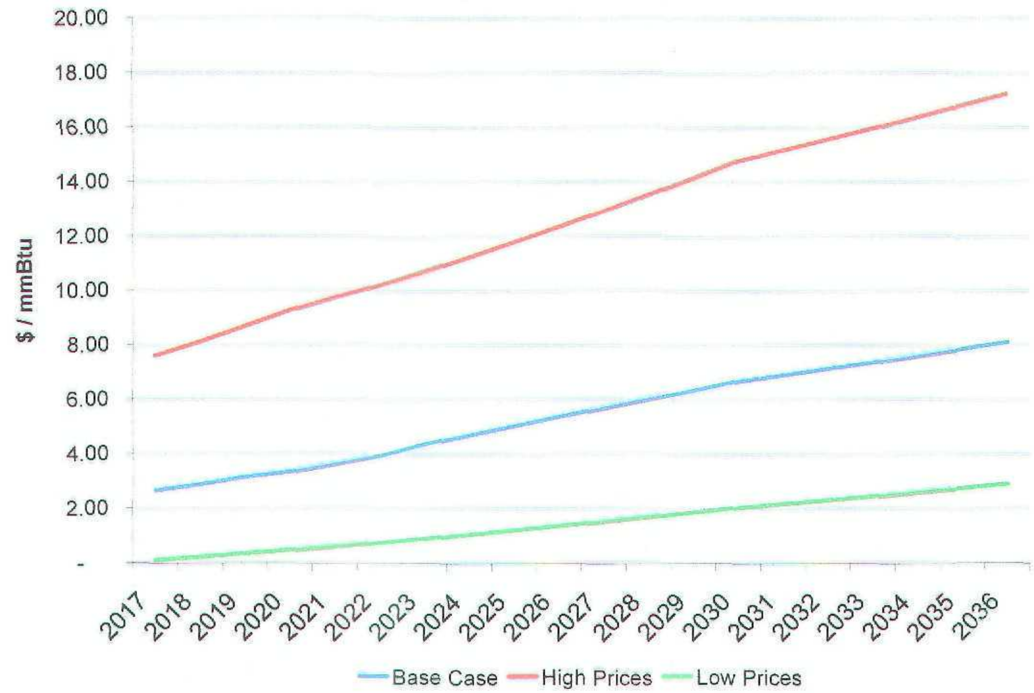
On the basis of the market prices and Project cost assumptions discussed in the preceding sections and rates of service assumptions described above, netback prices and upstream revenue net back to the point of production has been projected, as shown below

Table 11 Projected Average Netback Prices and Annual Upstream Revenue

Price Case	20-year Average Netback Revenue at Pint of Production ($ millions, nominal)	20-year Average Netback Price at Point of Production ($ / mmBtu)
Base Case	5.8	5.43
High Prices	1.6	12.62
Low Prices	13.4	1.45

The graph below shows the projected netback prices in each of the first 20 years of the Project's operating life.

Figure 35 Projected Netback Prices at the Point of Production

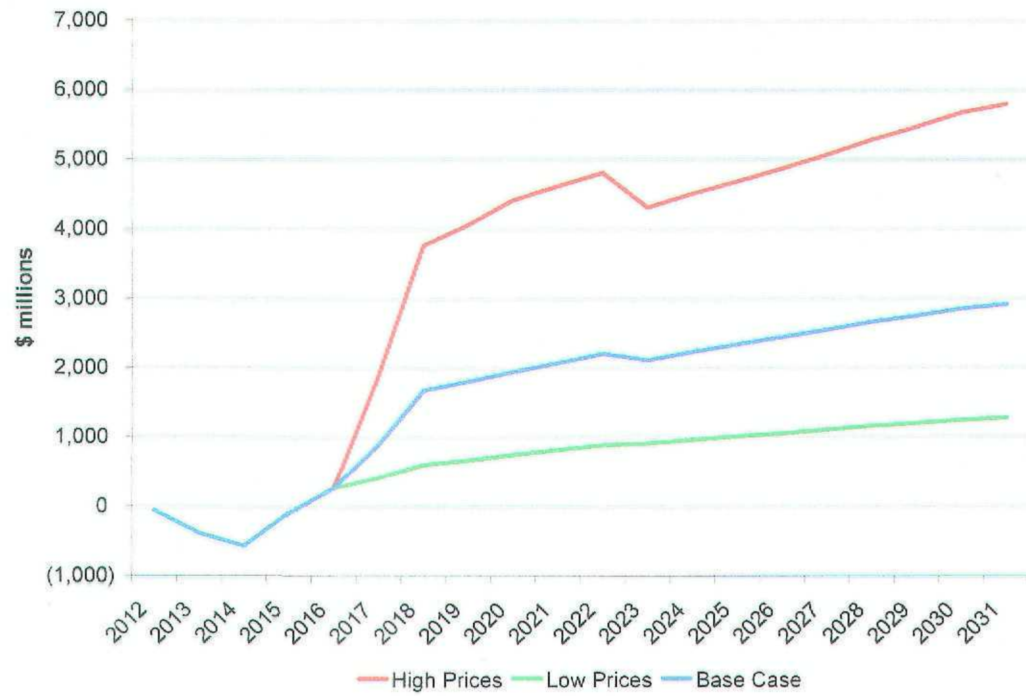


Detailed information on the modeling methodology can be obtained from the confidential Project financial model, attached as Appendix NN.

2.10.1.4 Cash Flows to the State of Alaska

Cash flows to the State from royalties (net of field cost allowance), production tax, property taxes, and corporate income taxes for the construction period and the first 20 years of the operating period have been estimated as shown below.

Figure 36 Projected Cash Flows to the State



The Projected NPVs of the State's cash flows is shown below.

Table 12 State Cash Flow Net Present Value ($ billions)

Price Case	Base Case	High Prices	Low Prices
Undiscounted	93.9	182.4	44.4
NPV @ 2%	53.7	105.7	24.7
NPV @ 5%	24.8	50.1	10.9
NPV @ 6%	19.6	39.7	8.5
NPV @ 8%	12.4	25.7	5.2

Detailed information on the modeling methodology can be obtained from the confidential Project financial model, attached as Appendix NN.

2.10.1.5 Competitive Analysis

The Project's economics have been compared with the proposed Alcan Highway project. For the purposes of such a comparison, it is of great importance that capital and other cost assumptions for each project are prepared on the same basis, otherwise the comparison may not be meaningful. Therefore, the analysis does not use the cost estimates for the proposed Alcan Highway project that have been publicly provided to date, as the Port Authority does not have access to proprietary data for that project and, therefore, cannot properly evaluate the basis of preparation of the cost estimates to ensure a proper comparison.

Rather, the analysis uses high level cost estimates for the Alaskan leg of the Alcan Highway project that have been previously provided to the Port Authority by Bechtel. As such estimates were prepared by Bechtel using the same methodology applied in the preparation of the estimates for the Port Authority's own Project, project comparison can be performed on a consistent basis. These prior cost estimates for the Alcan Highway project have been adjusted to a 2007 basis using the same cost escalation factor that was observed in the increase in the Port Authority's own Project costs in the 2007 update prepared for this Application.

The Port Authority and Bechtel have not estimated the cost of the Canadian leg of the Alcan Highway project. For the purposes of this analysis, the cost of this leg has been estimated using the assumption for the Alaskan leg, as described above and applying the relative cost factor between the Alaskan leg and the Canadian leg provided in publicly available cost estimates for the Alcan Highway project.[17]

Two Alcan cases were evaluated: 3.0 bscfd and 4.5 bcfd at the pipeline inlet. Using the extrapolation methodology described in the previous paragraph, the following EPC costs for the pipeline from Prudhoe Bay to Alberta were assumed

- 3.0 bcfd case: $23.8 billion
- 4.5 bcfd case: $27.5 billion

On the above basis, the economics of the two projects have been compared resulting in the netback prices as shown

Table 13 Projected 20-year Average Netback Prices for the All-Alaska Gasline and Alcan Highway Projects

	LNG Base Case (2.7 bcfd)	Alcan 3.0 bcfd	Alcan 4.50 bcfd
Average Netback Price at Point of Produciton ($ / mmBtu)	5.43	3.42	4.33
30-Year Reserve Requirements (Tcf)	30	34	51

As seen from the table above, the All-Alaska Gasline Project enjoys a netback pricing advantage ranging from $1.10 to $2.00 per $mmBtu, depending on the gas volume assumptions, resulting in a significant competitive advantage over the proposed Alcan Highway line. Higher netback prices are achieved on the basis of smaller volume and, therefore, smaller reserve requirements to support the project.

Detailed information on the modeling methodology can be obtained from the confidential Project financial model, attached as Appendix NN.

[17] Specifically, the Canadian leg capital cost has been assumed using a factor of 1.16, representing the relative cost relationship between the $5.8 billion and $5.0 billion estimates for the Canadian and Alaskan legs, as provided in the Fiscal Interest Findings accompanying the Stranded Gas Fiscal Contract proposed in 2006.

2.10.2 Project Technical Viability

2.10.2.1 Pipeline

The design of the Pipeline has been developed during the course of a number of studies carried out by Bechtel over the last few years, and the technical and execution issues are well understood. The design basis and construction planning have been developed in detail, which is provided in the Execution Plan in this Application. The key challenges of design and construction for partial permafrost, seismic conditions and with regard to the sensitive environmental issues along the pipeline route have been fully addressed, and the technical viability of the design has been demonstrated, with regard to both flow hydraulics and physical integrity. The summary level results of the conceptual pipeline flow simulations carried out so far, which were performed using the proprietary Gregg WinFlo computer program are shown below.

In the model prepared for this configuration, gas enters the pipeline system at 2220 psig and 28°F at the inlet to the North Slope compressor station and is delivered into the LNG plant at minimum pressure and temperature of 1,300 psig and 15.5°F. The flow of 2.7 bcfd is supported by two intermediate compression stations of approximately 48,000 and 53,000 hp at MP 320 and MP 629 respectively.

Gas composition is essentially the same as that identified in the RFA, but it is assumed that it will be delivered by the supplier(s) with CO2 removed to give a component of less than 100ppm, any mercury or hydrogen sulfide removed and dried to les than 0.1ppm water content. The assumed inlet conditions and composition are as follows:

Table 14 Assumed Gas Composition at the Pipeline Inlet

	Lean Gas Composition
Pressure	1150 psig
Temperature	40 °F
Methane	91.26 %Mol
Ethane	5.89 %Mol
Propane	1.73 %Mol
i-Butane	0.10 %Mol
n-Butane	0.20 %Mol
C5+	0.10 %Mol
Nitrogen	0.71 %Mol
H2S	0.00 %Mol
H20	0.00 %Mol
CO2	<100 ppm
Mercury	0.00 %Mol

During FEED, further work will be performed in order to adapt the design to the specific gas compositions and operating environment for this project. Simulation tools include Gregg WinFlo for determining the steady state pressure-flow relationships, and WinTran for real-time transient simulation will be used.

2.10.2.2 LNG Facilities

The most effective demonstration of the technical viability of the LNG plant is that the proposed design and project execution philosophy is the same as that which has been successfully employed by Bechtel on a number of similar developments around the world over the last 10 years, including Atlantic LNG in Trinidad, Egypt LNG, and plants in Darwin, and Equatorial Guinea. Bechtel was directly involved in the Alaskan Kenai LNG plant and is familiar with the particular issues concerning building and operating the proposed plant in Valdez Alaska. The design assumed for the purposes of this Application utilizes the proprietary ConocoPhillips Cascade technology which is extremely well-proven and is recognized for its efficiency and reliability. The potential use of alternative liquefaction technologies will be evaluated during the development phase.

The LNG plant design that forms the basis of the current application was developed over a significant period, and incorporates enhancements resulting from significant operational experience. A preliminary design appraisal was carried out on the modeling from a previous study, taking into account the inlet gas composition and environmental factors, and this determined that the requirements for operation in Valdez Alaska are well within the capability of the base design. Lower air temperatures actually enhance the efficiency of the process and lead to higher plant capacity than operation in warmer locations. Process modeling utilizes commercially available process simulation packages commonly utilized by the industry such as Hysys, Aspen, etc. The details of the plant configuration, horsepower requirements and the simulation techniques and results form an integral part of the ConocoPhillips and Bechtel proprietary LNG system design. Consequently, the information is maintained as strictly confidential and it is not released externally.

The LNG Facilities consists of multiple trains and is designed to handle varying feed gas compositions. The inlet feed pressure is 1,300 psia at a temperature of 15.5°F. Each LNG train is designed to produce 5.0 mmta, based on nominal capacity, of LNG product with high heating value in the range 1010–1100 Btu per standard cubic foot. The plant utilizes compression gas turbine units proven for refrigeration compression applications in the LNG industry.

During FEED, further work will be performed in order to optimize the design to the specific gas compositions and operating environment for this project.

2.10.2.3 EPA Compliance

Design, construction and operation of the pipeline, associated compression stations, LNG plant and marine terminal will be undertaken in a manner that complies with all applicable state and federal environmental standards and regulations as provided by environmental terms and conditions established by land use and operating permits for these facilities.

Figure 37 Overall Flow Scheme for the Project

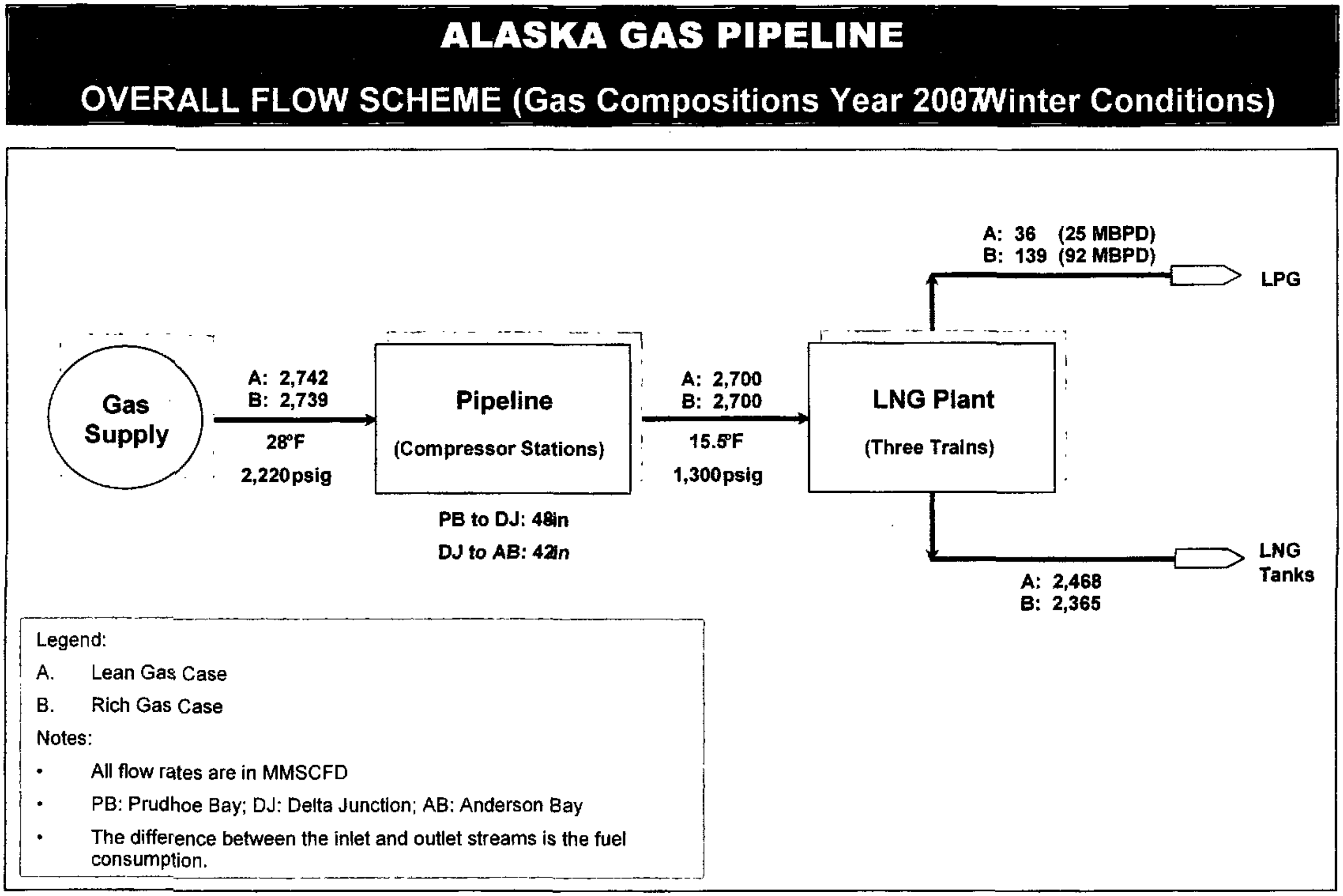


Figure 38 **Pressure Profile: 3 Compressor System -- Lean Gas 2007 (Winter)**
Flow Rate: 2.7 bcfd

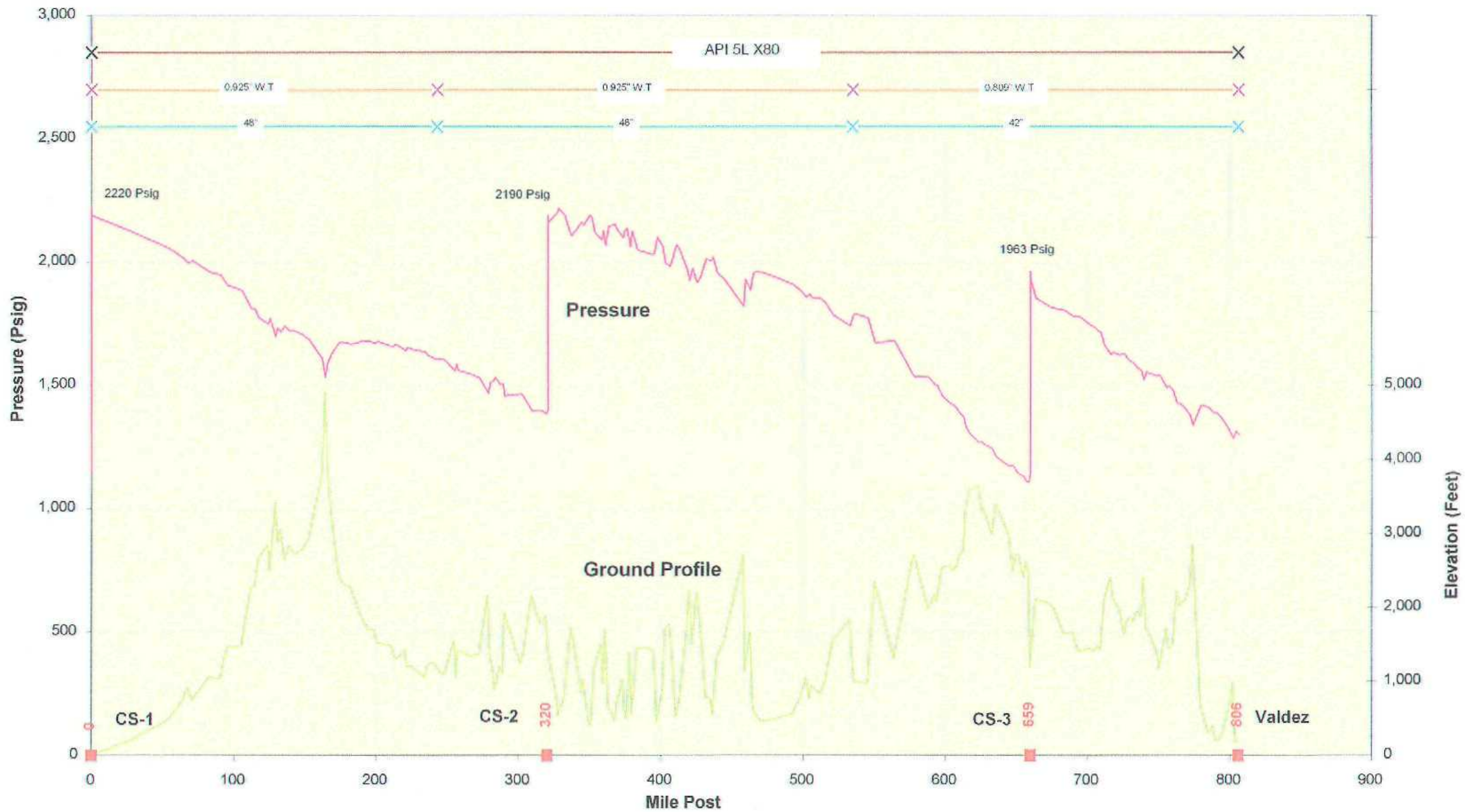
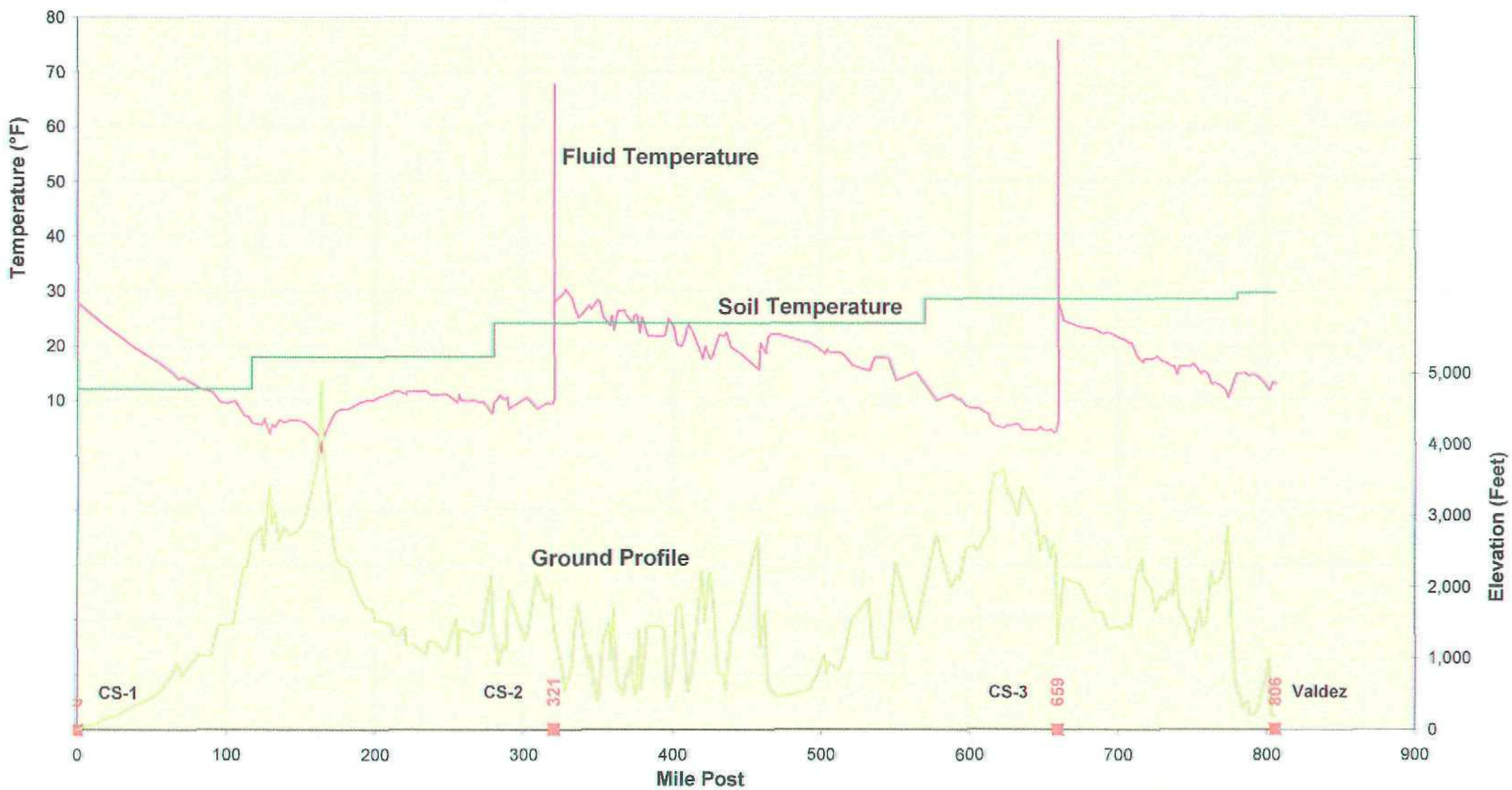


Figure 39 **Temperature Profile: 3 Compressor System – Lean Gas 2007 (Winter)**
Flow Rate: 2.7 bcfd



2.11 Proposed Reimbursement

The Port Authority hereby proposes, in a total dollar amount not to exceed $500,000,000, the following percentages for cost reimbursement pursuant to AS 43.90.130(9) as follows:

(a) for Qualified Expenditures incurred prior to the conclusion of the initial open season a reimbursement level of 50 percent;

(b) for Qualified Expenditures incurred after the conclusion of the initial open season:

(i) in the event that the initial binding open season results in firm transportation commitments to the Project that provide credit support sufficient to finance the construction of the Project, a reimbursement level of 50 percent of actual Qualified Expenditures incurred; and

(ii) in the event that the initial binding open season results in firm transportation commitments to the Project that do not provide credit support sufficient to finance the construction of the Project, a reimbursement level of 90 percent.

3. Former Point Thomson Unit

The Port Authority views commitment of natural gas from the former Point Thomson Unit ("**Point Thomson**") as critical to the success of any midstream project to monetize ANS gas. As discussed in Sections 2.2.3.1(a) and 2.7.1, however, the Port Authority is of the opinion that the current status of Point Thomson, decreases, rather than increases, Project risks associated with securing firm transportation commitments.

The Port Authority's long held belief that Point Thomson gas is critical to success of it Project efforts has resulted in it being at the forefront of encouraging, and ultimately demanding, development of the field's resources.

In 2004 and the first half of 2005, the Port Authority repeatedly approached the Point Thomson working interest owners, seeking to discuss and negotiate transportation arrangements for gas from the field. It eventually became clear that the former leaseholders were not willing to discuss committing gas to an independent project.

In the fall of 2005, the Port Authority filed extensive factual and legal briefing to DNR, demanding that the State terminate the unit and reclaim the acreage for re-leasing to upstream producers interested in bringing Point Thomson gas resources to market. Since that time, the Port Authority has continued to assist DNR in its efforts to clear title on Point Thomson, including actively participating in the administrate and superior court unit termination proceedings.

The Port Authority's close association with the termination process has left it confident that DNR's efforts will be successful, meaning the State could be in the position to begin the re-leasing process as soon as 2009. Because the Point Thomson reservoirs are largely delineated, and there is little exploration risk associated with the acreage, interest in re-leasing by upstream producers is expected to be strong. Consequently, DNR will be in a position to demand and receive bid terms more favorable than those traditionally received by the State for exploration acreage.

To guarantee maximum ultimate hydrocarbon recovery from Point Thomson, the Port Authority recognizes that gas cycling may be required for a number of years before significant gas offtake from the field is appropriate. Thus the Port Authority commits to immediately begin working with DNR and the AOGCC to establish rules for Point Thomson gas offtake so that the timing of Point Thomson gas availability to the Project can be determined before the Project's initial open season. The Port Authority will also work with the State to embed express "date certain" development commitments into the new leasing arrangements to ensure: (a) cycling, if required by the AOGCC, occurs rapidly, possibly even before Project construction; and (b) Point Thomson gas shipments through the Project are coordinated to maximize recovery in light of Point Thomson and Prudhoe Bay reservoir needs (i.e., Point Thomson gas sales should occur such that total recovery is maximized from both units).

Additionally, the Port Authority believes DNR should take this opportunity to seek a substantially larger share of Point Thomson profits than it has received in the past under its traditional exploration lease arrangements. Structuring the lease sales with royalty or a net profit interest ("**NP**")[18] as one of the key bid variables can be expected to result in a high level of State "take." The Port Authority believes the original Northstar lease sales provide a good analogy for what the State might achieve with Point Thomson.

Northstar is a joint offshore State/federal oil and gas unit located to the north of the Prudhoe Bay unit. In 1979, the Northstar prospect was first put out for bid on a NP bid basis. Four State leases were bid in 1979,[19] and one in 1983,[20] with Amerada Hess and Shell as the primary leaseholders. The four 1979 leases gave the State a one-fifth royalty share plus an 89% NP. The 1983 lease gave the State a one-eighth royalty share plus a 40% NPI, for an average NP on the State's share of the unit of roughly 80%.

Total State "take" can be viewed as the amount of profits on oil and gas the State gets after it collects its royalty share, NP (if any), and severance, property, and state income taxes. For the Northstar leases in the 1980s this can be conservatively estimated at over 90%, assuming: (a) nominal severance taxes because of the later adopted Economic Limit Factor; (b) nominal property taxes (which are small in the total picture); (c) State income taxes of about 9% with an effective rate about half that after deductions; (d) a blended 19% royalty; and (e) a blended 80% NP.

A re-leasing of Point Thomson acreage would share many characteristics with the State Northstar lease sales, including a high oil price environment, but would be more attractive to the lessee because of the lack of exploration risk. Consequently, it is reasonable to assume the State will be able to achieve a similar 90% take for Point Thomson. According to a recent 2007 DOE study this is more than triple the 26.1% take (pre-PPT) Alaska would have historically expected ANS-wide after a major gas sale with West Coast oil at $60 per barrel.[21]

The same 2007 DOE study, assuming a flat price of $60 per barrel for ANS crude West Coast prices and ultimate Point Thomson recovery of 7.2 tcf of gas and 390 million barrels of condensates and oil, estimated that the State's total nominal take over the life of Point Thomson under the old lease terms would be approximately $24.3 billion, or a 26.9%.[22] If on re-leasing the State can achieve take percentages comparable to the Northstar leases, i.e., about 90%, the State would expect $81.0 billion over the life of the field given the same pricing, cost and ultimate recovery assumptions.

This figure is larger than DOE's estimated total $77.9 billion State take from all ANS production in the future if a major gas sale does not occur.[23] If a major gas sale does

[18] A net profit interest can be simplistically represented as a share of total lease revenue minus the field development costs (including interest) and State royalty (Net Profit ≈ Gross Revenue – Field Costs – State Royalty). See 11 AAC 83.200-.228.

[19] ADL 312798, ADL 312799, ADL 312808, ADL 312809.

[20] ADL 355001.

[21] United States Department of Energy, *Alaska North Slope Oil and Gas - A Promising Future or an Area in Decline?*, Full Report 3-127 (August 2007).

[22] *Id.* at 3-139.

[23] *Id.* at 3-126.

occur, DOE predicts total ANS State take under the old Point Thomson lease terms will equal approximately $153 billion,[24] meaning the additional $56.7 billion the State could bring in with a lease similar to the Northstar lease would increase State oil and gas revenues by about 37% over the life of the ANS.

Table 15 DOE Forecast of Economic Results for Point Thomson

Variable	**$25/bbl**	**$35/bbl**	**$50/bbl**	**$60/bbl**
Total investments	$4,639,810	$4,639,810	$4,639,810	$4,639,810
Total operating costs	$528,964	$528,964	$528,964	$528,964
State royalty	$3,912,862	$6,450,479	$10,256,900	$12,794,517
State taxes – Severance	$2,847,429	$4,630,958	$7,306,252	$9,089,781
State taxes – Income	$512,468	$936,974	$1,573,737	$1,998,244
State taxes – Other	$441,063	$441,063	$441,063	$441,063
State Total (Royalty & Taxes)	**$7,713,822**	**$12,459,474**	**$19,577,952**	**$24,323,605**
Federal taxes	**$5,980,620**	**$10,647,378**	**$17,647,510**	**$22,314,268**
Industry net income	**$11,653,704**	**$20,712,700**	**$34,301,198**	**$43,360,197**

Source: DOE

It can thus be seen that the magnitude of potential economic rents from Point Thomson are significant. If re-leased at anything approaching the NP shares originally received by the State in the Northstar leases, and combined with fixed development timelines, such terms will maximize the economic benefits to the State, while allowing Point Thomson gas, along with Prudhoe Bay gas, to provide the shipping commitments that will anchor the construction of an All-Alaska natural gas pipeline project.

[24] *Id.* at 3-141.

Appendix A

Glossary of Selected Terms and Abbreviations

Glossary of Selected Defined Terms and Abbreviations

Term	Definition
AGIA	Alaska Gasline Inducement Act, AS 43.90.010 et seq.
ANGDA	Alaska Natural Gas Development Authority
ANGTA	Alaska Natural Gas Transportation Act of 1976, 15 U.S.C. § 719 et seq.
ANS	Alaska North Slope
bcfd	billion cubic feet per day
bcm	billion cubic meters
Bechtel	the Bechtel Corporation
BLM	U.S. Bureau of Land Management
DES	delivered ex-ship
DOE	U.S. Department of Energy
EIA	Energy Information Administration
EPC	engineering, procurement and construction
FEED	front end engineering design
FEIS	final environmental impact statement
FERC	Federal Energy Regulatory Commission
FNSB	Fairbanks North Star Borough
FOB	free-on-board
GCP	the proposed gas conditioning plant at Prudhoe Bay
GCP Participants	the entities that own and operate GCP
IEEJ	Institute of Energy Economics, Japan
JCC	Japan Crude Cocktail
License	the license awarded pursuant to AGIA
LNG	liquefied natural gas
LNG Facilities	the proposed liquefaction, and fractionation facilities, LNG and LPG storage, vessel loading and related facilities in Valdez
LPGs	liquid petroleum gases
m3	cubic meters
mbpd	million barrels per day
mmBtu	million British thermal units
mmta	million metric tons per annum
MOL	Mitsui O.S.K. Lines, Ltd.

MOL Companies	MOL and its subsidiaries BGT Limited and BLNG Inc.
NAESB	North American Energy Standards Board
NGA	the Natural Gas Act, 15 U.S.C. § 717 et seq.
NGLs	natural gas liquids
NPV	net present value
NSF	National Science Foundation
NTP	notice to proceed
NYMEX	New York Mercantile Exchange
Pipeline	the 806-mile overland natural gas pipeline extending from Prudhoe Bay to tidewater at Valdez proposed by the Port Authority
Port Authority	the Alaska Gasline Port Authority
Project	the project to develop, finance, construct and operate the Pipeline, LNG Facilities and GCP
RCA	Regulatory Commission of Alaska
RFA	Request for Applications
SIMP	stakeholder issues management plan
TAGS	Trans Alaska Gas System
TAPS	Trans-Alaska Oil Pipeline System
VLGCs	very large gas carriers
WTI	West Texas Intermediate
YPC	Yukon Pacific Corporation

APPENDIX A
APPLICATION CHECKLIST

	Statute	Requirement	RFA Reference	Applicant's Reference
	43.90.130(1)	Applicant must be filed by the deadline	1.6	N/A
	43.90.130(2)	Provide a thorough description of a proposed natural gas pipeline project for transporting natural gas from the North Slope to market, which description may include multiple design proposals, including different design proposals for pipe diameter, wall thickness, and transportation capacity, and which description shall include:	2.1	2.1
	(A)	The route proposed for the natural gas pipeline, which may not be the route described in AS 38.35.017(b);	2.1.1.	2.1.1.3 Appendix I
	(B)	The location of receipt and delivery points and the size and design capacity of the proposed natural gas pipeline at the proposed receipt and delivery points, except that this information is not required for in-state delivery points unless the application proposes specific in-state delivery points;	2.1.1	2.1.1.4 2.2.3.9
	(C)	An analysis of the project's economic and technical viability, including a description of all pipeline access and tariff terms the applicant plans to offer;	2.10. and 2.2.3.4.	2.10
	(D)	An economically and technically viable work plan, timeline, and associated budget for developing and performing the proposed project, including field work, environmental studies, design and engineering, implementing practices for controlling carbon emissions from natural gas systems as established by the United States Environmental Protection Agency, and complying with all applicable state, federal and international regulatory requirements that affect the proposed project, the applicant shall address the following;	2.2 to 2.8	2.2 to 2.8 Appendix OO Appendix PP Appendix QQ

	(D) (i)	If the proposed project involves a pipeline into or through Canada, a thorough description of the applicant's plan to obtain necessary rights-of-way and authorizations in Canada, a description of the transportation services to be provided and a description of rate-making methodologies the applicant will propose to the regulatory agencies, and an estimate of rates and charges for all services;	2.2.3.13 2.2.4.1 2.2.4.5	2.2.3.13 2.2.4.5 Appendix OO
	(D) (ii)	If the proposed project involves marine transportation of liquefied natural gas, a description of the marine transportation services to be provided and a description of proposed rate-making methodologies; an estimate of rates and charges for all services by third parties; a detailed description of all proposed access and tariff terms for liquefaction services or, if third parties would perform liquefaction services, identification of the third parties and the terms applicable to the liquefaction services; a complete description of the marine segment of the project including the proposed ownership, control, and cost of liquefied *natural gas tankers, the management of* shipping services, liquefied natural gas export, destination, re-gasification facilities, and pipeline facilities needed for transport to market destinations, and the entity or entities that would be required to obtain necessary export permits and licenses or a certificate of public convenience and necessity from the Federal Energy Regulatory Commission for the transportation of liquefied natural gas in interstate commerce if United States markets are proposed; and all rights-of-way or authorizations required from a foreign country;	2.1.3 2.2.3.14	2.1.3 2.2.3.14 Appendix L Appendix S Appendix RR
	43.90.130(3)	If the proposed project is within the jurisdiction of FERC, does the Application commit:		

	(A)	Conclude, by a date certain that is not later than 36 months after the date the license is issued, a binding open season that is consistent with the requirements of 18 C.F.R. Part 157, Subpart B (Open Season for Alaska Natural Gas Transportation Projects) and 18 C.F.R. 157.30 – 157.39;	2.2 2.2.4.3 2.2.3	2.2.4.3
	(B)	Apply for Federal Energy Regulatory Commission approval to use the pre-filing procedures set out in 18 C.F.R. 157.21 by a date certain, and use those procedures before filing an application for a certificate of public convenience and necessity, except where the procedures are not required as a result of sec. 5 of the President's Decision issued under 15 U.S.C. 719 et seq. (Alaska Natural Gas Transportation Act of 1976); and	2.2 2.2.4.3	2.2.4.3
	(C)	Apply for a Federal Energy Regulatory Commission certificate of public convenience and necessity to authorize the construction and operation of the proposed project described in this section by a date certain;	2.2 2.2.4.3	2.2.4.3
	43.90.130(4)	If the proposed project is within the jurisdiction of the Regulatory Commission of Alaska, commit to		
	(A)	Conclude, by a date certain that is not later than 36 months after the date the license is issued, a binding open season that is consistent with the requirements of AS 42.06;	2.2 2.2.4.4	2.2.4.4
	(B)	Apply for a certificate of public convenience and necessity to authorize the construction and operation of the proposed project by a date certain;	2.2 2.2.4.4	2.2.4.4
	43.90.130(5)	Commit that after the first binding open season, the applicant will assess the market demand for additional pipeline capacity at least every two years through public nonbinding solicitations or similar means;	2.4 2.4.1.1	2.4.1.1
	43.90.130(6)	Commit to expand the proposed project in reasonable engineering increments	2.4 2.4.1.2	2.4.1.2

		and on commercially reasonable terms that encourage exploration and development of gas resources in this *state*		
	43.90.130(7)	(A) will propose and support the recovery of mainline capacity expansion costs, including fuel costs, from all mainline system users through rolled-in rates as provided in (B) and (C) of this paragraph or through a combination of incremental and rolled-in rates as provided in (D) of this paragraph);	2.4 2.4.1.3 2.4.1.1	2.4.1.3
	(B)	Will propose and support the recovery of mainline capacity expansion costs, including fuel costs, from all mainline system users through rolled-in rates; an applicant is obligated under this subparagraph only if the rolled-in rates would increase the rates (i) not described in (ii) of this subparagraph by not more than 15 percent above the initial maximum recourse rates for capacity acquired before commercial operations commence; in this sub-subparagraph "initial maximum recourse rates" means the highest cost-based rates for any specific transportation service set by the Federal Energy Regulatory Commission, the Regulatory Commission of Alaska, or the National Energy Board of Canada, as appropriate, when the pipeline commences commercial operations; (ii) by no more than 15 percent above the negotiated rate for pipeline capacity on the date of commencement of commercial operations where the holder of the capacity is not an affiliate of the owner of the pipeline project; for the purpose of this sub-subparagraph "negotiated rate" means the rate in a transportation service agreement that provides for a rate that varies from the otherwise applicable cost-based rate, or recourse rate, set out in a gas pipeline's tariff approved by the Federal Energy	2.4 2.4.1.3 2.4.1.1	2.4.1.3

		Regulatory Commission, the Regulatory Commission of Alaska, or the National Energy Board of Canada, as appropriate; or (iii) for capacity acquired in an expansion after commercial operations commence, to a level that is not more than 115 percent of the volume-weighted average of all rates collected by the project owner for pipeline capacity on the date commercial operations commence;		
	(C)	Will, if recovery of mainline capacity expansion costs, including fuel costs, through rolled-in rate treatment would increase the rates for capacity described in (B) of this paragraph, propose and support the partial roll-in of mainline expansion costs, including fuel costs, to the extent that rates acquired before commercial operations commence do not exceed the levels described in (B) of this paragraph;	2.4 2.4.1.3 2.4.1.1	2.4.1.3
	(D)	May, for the recovery of mainline capacity expansion costs, including fuel costs, that, under rolled-in rate treatment, would result in rates that exceed the level in (B) of this paragraph, propose and support the recovery of those costs through any combination of incremental and rolled-in rates;	2.4 2.4.1.3 2.4.1.1	2.4.1.3
	43.90.130(8)	State how the applicant proposes to deal with a North Slope gas treatment plant, regardless of whether that plant is part of the applicant's proposal, and, to the extent that the plant will be owned entirely or in party by the applicant, commit to seek certificate authority from the Federal Energy Regulatory Commission if the proposed project is engaged in interstate commerce, or from the Regulatory Commission of Alaska if the project is not engaged in interstate commerce; for a North Slope gas treatment plant that will be owned entirely or in part by the applicant, for rate-making purposes, commit to value	2.2 2.2.3.12	2.1.2 2.1.4.1 2.2.3.12 2.7.2

		previously used assets that are part of the gas treatment plant at net book value; describe the gas treatment plant, including its design, engineering, construction, ownership, and plan of operation; the identity of any third party that will participate in the ownership or operation of the gas treatment plant, and the means by which the applicant will work to minimize the effect of the costs of the facility on the tariff.		
	43.90.130(9)	Propose a percentage and total dollar amount for the state's reimbursement under AS 43.90.110(a)(1)(A) and (B) to be specified in the license.	2.11	2.11
	43.90.130(10)	Commit to propose and support rates for the proposed project and for any North Slope gas treatment plant that the applicant *may own, in whole or in part*, that are based on a capital structure for rate-making that consists of not less than 70 percent debt;	2.2 2.2.3.5	2.8.3
	43.90.130(11)	Describe the means for preventing and managing overruns in costs of the proposed project, and the measures for minimizing the effects on tariffs from any overruns;	2.2.3.6 2.2.3.11	2.2.3.6 2.2.3.11 2.3.2
	43.90.130(12)	Commit to provide a minimum of five delivery points of natural gas in this state	2.1.1 2.2.3.9	2.2.3.9 2.2.4.4
	43.90.130(13) (A)	Commit to offer firm transportation service to delivery points in this state as part of the tariff regardless of whether any shippers bid successfully in a binding open season for firm transportation service to delivery points in this state, and commit to offer distance-sensitive rates to delivery points in this state consistent with 18 C.F.R. 157.34(c)(8); and	2.2.3.9	2.2.3.9
	(B)	Commit to offer distance-sensitive rates to delivery points in the state consistent with 18 C.F.R. 157.34(c)(8);	2.2.3.9	2.2.3.9
	43.90.130(14)	Commit to establish a local headquarters in this state for the proposed project	2.2.5	2.2.5
	43.90.130(15) (A)	Hire qualified residents from throughout the state for management, engineering,	2.3.4	2.3.4

		construction, operations, maintenance, and other positions on the proposed project.		
	(B)	Contact with businesses located in the state;	2.3.4	2.3.4
	(C)	Establish hiring facilities or use existing hiring facilities in the state;	2.3.4	2.3.4
	(D)	Use, as far as is practicable, the job centers and associated services operated by the Department of Labor and Workforce Development and an Internet-based labor exchange system operated by the state.	2.3.4	2.3.4
	43.90.130(16)	Waive the right to appeal the rejection of the application as incomplete, the issuance of a license to another applicant, or the determination under AS 43.90.180(b) that no application merits the issuance of a license;	1.13.7 Appendix D	1.1
	43.90.130(17)	Commit to negotiate, before construction, a project labor agreement to the maximum extent permitted by law; in this paragraph, "project labor agreement" means a comprehensive collective bargaining agreement between the licensee or its agent and the appropriate labor representatives to ensure expedited construction with labor stability for the project by qualified residents of the state;	2.3.3	2.3.3 Appendix MM
	43.90.130(18)	Commit that the state reimbursement received by a licensee may not be included in the applicant's rate base, and shall be used as a credit against licensee's cost of service;	2.2.3.10	2.2.3.10
	43.90.130(19)	Provide a detailed description of the applicant, all entities participating with the applicant in the application and the project proposed by the applicant, and persons the applicant intends to involve in the construction and operation of the proposed project; the description must include the nature of the affiliation for each person, the commitments by the person to the applicant, and other information relevant to the	2.8	2.2.3 2.8 2.9 Appendix C Appendix L Appendix S Appendix RR

		commissioners' evaluation of the readiness and ability of the applicant to complete the project presented in the application;		
	43.90.130(20)	Demonstrate the readiness, financial resources, and technical ability to perform the activities specified in the application by describing the applicant's history of compliance with safety, health, and environmental requirements, the ability to follow a detailed work plan and timeline and the ability to operate within an associated budget.	All of Section 2 and 2.9	2.9
		Required documents;		
		Signed application with corporate approvals	1.10.4 1.13.3	See application
		Signed certification, Appendix E	1.13.3	See application
		List of Applicant's Required and Additional Commitments		N/A
		Electronic Copy of Entire Application (On CD in PDF Print Ready Format)	1.5	CDs attached
		List of Data for Applicants to Provide in MS Excel Format, Appendix C (On CD in MS Excel)	2.10.1	Appendix NN
		Identification of Proprietary Information and Trade Secrets and summary of Information for Public	1.13.6	G-5, I, K, L, V, CC, DD, EE, FF, GG, II, JJ, KK, NN, RR

Applicant's Name [signature]
William W. Walker, Project Manager
Alaska Gasline Port Authority

APPENDIX A-1

ALASKA GASLINE PORT AUTHORITY
RESPONSE TO
REQUEST FOR CLARIFYING INFORMATION
CHECKLIST
(December 18, 2007)

Request No.	***December 11, 2007 Requests for Information***	***RFA Reference***	***AGPA's Reference***
	Request No. 1		
1.a	Please clearly identify and provide a detailed description of the primary design of the project proposed by the Application.	2	1.2.1 1.2.2 1.2.3 2.1.1 2.1.2 2.1.3 2.1.4
1.b	Identify all of the Sections and Appendices of the Application that contain the data required to support the project described in (a) above, and provide a detailed explanation of how the data relates to the project.	2	2 Appendix I Appendix T Appendix U Appendix V Appendix CC Appendix EE Appendix FF Appendix GG Appendix HH Appendix JJ Appendix KK Appendix OO Appendix PP Appendix QQ
	Request No. 2		
2.	For each Application section listed below, please identify all of the Sections and the Appendices of the Application, other than Section 7.2 that contain the data that are responsive to the respective RFA Sections. In addition, please provide a detailed explanation of how the data relates to the project		

Request No.	*December 11, 2007 Requests for Information*	*RFA Reference*	*AGPA's Reference*
	described in response to 1(a) above.		
2.a	For Application Sections 3.2.2, 3.3, 3.4 and 9.2 responding to the requirement in RFA Section 2.1 to describe the Project components.	2.1	1.2.1 1.2.2 1.2.3 2.1 2.4.2 2.7.2
2.b	For Application Sections 4.1, 4.3.1 and 8.1 responding to the requirements in RFA Section 2 introduction and RFA Sections 2.2 and 2.2.3.13 to describe a Project Development Plan.	2 Introduction 2.2 2.2.3.13	2.2 2.2.3.13
2.c	For Application Sections 5.1, 5.2 and 8.2 responding to the requirements in RFA Section 2 introduction and RFA Section 2.3.1 to provide a Project Execution Plan.	2 Introduction 2.3.1	2.3.1 Appendix PP
2.d	For Application Section 9.4, responding to requirements in RFA Section 2.3.2 to provide a comprehensive capital cost management plan.	2.3.2	2.3.2 2.9 Appendix PP
2.e	For Application Section 13, responding to the requirements in RFA Section 2.10.2 to provide sufficient information to demonstrate and enable the state to verify technical viability.	2.10.2	2.10.2
	Request No. 3		
3.a	Please identify all of the Sections and Appendices of the Application that contain data and analysis of the economic viability of the project and provide a detailed explanation of how the data and analysis relates to the project described in response to 1(a)	2.10.1	2.5 2.10.1 Appendix NN

Request No.	***December 11, 2007 Requests for Information***	***RFA Reference***	***AGPA's Reference***
	above.		
3.b	In addition, please explain how Appendix NN explains the economic viability of and otherwise supports the project described in response to 1(a) above.	2.10.1	2.10.1
	Request No. 4		
4.a	Please identify all of the Sections and Appendices of the Application that contain the pipeline access and tariff terms the AGPA plans to offer and provide a detailed explanation of how the terms related to the project described in response to 1(a) above.	2.2.3.4	2.2.3.4 2.10.1 Appendix NN
4.b	Please clarify and explain the statement on page 28 of the Application that the Applicant "plans to use existing interstate pipeline tariffs as a model for its terms and conditions of service."	2.2.3.4	Reworded in 2.2.3.4
4.c	Please identify all of the Sections and Appendices of the Application that contain information responsive to the items listed below and provide a detailed explanation of how the terms relate to the pipeline portion of the project described in response to 1(a) above:		
4.c.i	Description of proposed ratemaking methodologies;	2.2.3.4	2.2.3.4 2.2.3.5 2.2.3.6 2.2.3.7 2.2.3.8
4.c.ii	Estimate of rates and charges for all services by third parties.	2.2.3.4	2.2.3.5 2.10.1.3

Request No.	*December 11, 2007 Requests for Information*	*RFA Reference*	*AGPA's Reference*
			Appendix NN
	Request No. 5		
5.a	Description of proposed ratemaking methodologies for liquefaction portion of the Project;	2.2.3.14	2.10.1.3 2.2.3.14(f)
5.b	Estimate of rates and charges for all services by third parties for liquefaction portion of the Project;	2.2.3.14	2.10.1.3 Appendix K
5.c	Detailed description of all proposed access and tariff terms for liquefaction services, or, if third parties would perform liquefaction services, identification of the third parties and the terms applicable to the liquefaction services.	2.2.3.14	2.2.3.14
	Request No. 6		
6.	Please identify and explain where in the Financial Model, Appendix NN, the information evidencing Applicant's financial resources and capabilities to perform Development and Execution of the proposed project appears. In addition, please provide a detailed explanation of how the data relates to the project described in response to 1(a) above.	2.8.2	2.8 2.9
	Request No. 7		
7.	Consistent with RFA Section 2.8.1, please provide a detailed description of each entity referenced in Application Section 10.1 with whom Applicant has a written commitment currently in effect and provide a copy of the written commitments.	2.8.1	2.8 2.9 Appendix C Appendix L Appendix S Appendix RR
	Request No. 8		
8.	Please identify all of the Sections and	2.9	2.8

Request No.	*December 11, 2007 Requests for Information*	*RFA Reference*	*AGPA's Reference*
	Appendices of the Applicant that contain the information required by RFA Section 2.9 and provide a detailed explanation of how the information relates to the project described in response to 1(a) above.		2.9
Request No. 9			
9.	Please clarify the reimbursement percentage AGPA proposes prior to the close of the first binding open season and after the close of the first binding open season.	2.11	2.11
Request No. 10			
10.	Application Section 4.3 Commercial Plan for Pipeline, addresses third-party Operation and Maintenance of the pipeline. Please identify the third party or parties that AGPA proposes to operate the pipeline.		2.2.3 2.4.2

Applicant's Name ___________

William M. Walker, Project Manager
Alaska Gasline Port Authority